1999/2000 Electric Tariff Applications

ATCO Electric Ltd.
EPCOR Generation Inc.
EPCOR Transmission Inc.
TransAlta Utilities Corporation

Volume 1

Alberta Energy and Utilities Board

1999/2000 ELECTRIC TARIFF APPLICATIONS

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1. INTRODUCTION AND IMPLEMENTATION

(a) Background

The Alberta Energy and Utilities Board (the Board, AEUB, EUB) received applications dated 30 October 1998 from Alberta Power Limited, Edmonton Power Generation Inc., Edmonton Power Transmission Inc. and TransAlta Utilities Corporation (TransAlta) respecting general tariff applications (GTA) for the 1999 and 2000 test years (the Applications). Alberta Power Limited changed its name to ATCO Electric Ltd. (AE) and its Application will be considered to have been filed by AE. Edmonton Power Generation Inc. and Edmonton Power Transmission Inc. changed their names to EPCOR Generation Inc. and EPCOR Transmission Inc., respectively in October 1999. Therefore this Decision will refer to EPCOR Generation Inc. (EPGI) and EPCOR Transmission Inc (EPTI). The Applications were made pursuant to sections 29, 31.4, 33, 36, 49, 51, and 54 of the *Electric Utilities Act* (EU Act).

AE, EPGI and TransAlta were seeking approval of their respective generation tariffs, comprising their Unit Obligation Prices and their Aggregate Reservation Price. AE, EPTI and TransAlta were seeking approval of their respective transmission tariffs, comprising their transmission charge to the Transmission Administrator (TA) and the Terms and Conditions of Service pursuant to which the TA will use those facilities. Additionally AE and TransAlta were seeking approval of their respective distribution revenue requirements.

Notice of hearing was published on 12 November 1998 in the major daily newspapers in Alberta. Notice was also served on interested parties by fax on 9 November 1998. The notice included a schedule of dates for the proceeding.

Prior to the receipt of the Applications, the Board provided a proposed timetable for the proceedings. The Board also allowed for and encouraged the possibility that parties might engage in negotiations before or during the scheduled proceedings. The Board convened a meeting with interested parties prior to the filing of the Applications to discuss minimum filing requirements, the continued applicability of outstanding directions from a previous Board Decision U97065, and other matters of concern. With the intent of encouraging a more efficient process, Board staff issued a letter on 14 September 1998 encouraging the following.

> It is the expectation of the Board that the Utilities provide full and complete evidence that support their 1999/2000 applications. Additionally, it is hoped that intervening parties focus on substantive issues and, where possible, do not attempt to revisit areas which were examined at length in the 1996 proceeding.

The Board convened an Advice and Direction meeting on 17 December 1998. This meeting was called to facilitate the consideration of alternatives to the hearing process to deal with the Applications. Further to the discussions at the Advice and Direction meeting, the Board engaged a facilitator to meet with the Utilities and all intervening parties to identify issues of interest and, if possible, to identify alternative processes that could be utilized to address issues such as:

1. INTRODUCTION AND IMPLEMENTATION
(a) Background

- Negotiated Settlements,
- Technical Meetings in advance of the hearing to address certain issues.

The outcome was that parties were not willing or able to engage in alternative mechanisms in general. As such, the process did not lead to the pursuit of any alternatives to the hearing process except the commitment that parties would consider the possibility of undertaking a negotiated settlement process once the exchange of information requests and responses were completed.

The Board also held pre-hearing conferences respecting the Applications on 26 January 1999 and 10 February 1999 to deal with further outstanding issues and with the expectation that they would encourage a more efficient hearing process.

On 22 April 1999 the Board received an application from AE to approve a negotiated settlement agreement that it had reached with interested parties on most aspects of its GTA. The Board issued Decision U99046 on 10 May 1999 approving AE's settlement agreement, the rates arising from it and AE's revenue requirement for 1999 and 2000. This Decision deals with the aspects of the AE application that were not covered in the settlement.

The hearing was held at the Board's offices in Edmonton, Alberta starting 29 March and concluding on 11 June 1999 with N. W. MacDonald, P.Eng., B. T. McManus, Q.C. and A. J. Berg, P.Eng. sitting as the Board Panel. Dates for argument and reply to argument were set at 28 June 1999 and 19 July 1999. The Hearing was then considered to have been concluded on July 19, 1999. Having heard the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons respecting the Applications of the Utilities.

The Board's Decision is structured as follows:

Volume 1	**Part 1 – General:** Deals with matters generic to two or more of the Utilities
Volume 2	**Part 2 – AE:** Deals with matters specific to AE and sets out the Board's findings respecting the aspects of AE's Application not covered by its negotiated settlement.
Volume 2	**Part 3 – EPI:** Deals with matters relating both jointly and individually to EPGI and EPTI and sets out the Board findings respecting the Applications of each of them.
Volume 2	**Part 4 – TAU:** Deals with matters specific to TransAlta and sets out the Board findings respecting the aspects of TransAlta's Application.
Volume 2	**Appendices**

1. INTRODUCTION AND IMPLEMENTATION
(a) Background

Volume 2	**Parties Participating in the Proceeding – Utilities and Intervenors**
Volume 2	**References**
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(b) Refiling Matters

During the course of the proceedings, interested parties identified certain corrections and adjustments to the Applications. The Utilities agreed to incorporate these corrections and adjustments in a refiling.

Further, the Board's findings in this Decision will necessitate a refiling of EPGI, EPTI and TransAlta's application schedules to enable the Board to complete its statutory role of fixing just and reasonable prices and rates.

The issue for the Board to decide in this section is what process should be followed to ensure the refilings comply with the Board's findings in this Decision.

Position of the FIRM Customers

The FIRM Customers noted the Board's ruling that it would direct the Utilities to make their refiling for 1999 and 2000 using actual plant balances as of 1 January 1999. The FIRM Customers stated:

> Accordingly, the FIRM Customers' comments and observation are based on the assumption this ruling will be adhered to by each of the applicants.[1]

Position of ENMAX

ENMAX submitted that the Board should pay particular attention to the refilings to ensure compliance with its rulings respecting the 1998 closing balances for rate base and capitalization. ENMAX specifically requested the Board to ensure that the impact of revisions to TransAlta's depreciation are properly reflected and accounted for in the return and income tax components for each of generation, transmission and distribution. ENMAX also expressed concern respecting refilings of pension reserve and financial information.

ENMAX summarized its position as follows:

> If the refiling contains both corrections and Board directions there will be concerns regarding the correctness of the refilings in regard to the so called corrections. As well, the magnitude of the corrections provide a risk for further

[1] FIRM Customers Argument, p.66

error. Therefore the Board should provide for an information request process and additional time for parties to review the refiling.[2]

Position of TransAlta

TransAlta submitted the following:

> To suggest, as ENMAX does, that because of corrections "the Board should provide for an information request process and additional time for parties to review the refiling" ..would be absurd and would serve only to add to the interested parties' and the Board's already busy schedules. It can only be justified if the intention is to have the hearing continue as an audit without end. With respect, the Board and parties have better things to do.[3]

Board Findings

The Board has found it necessary to direct the Utilities to refile their Applications to reflect the findings of the Board in this Decision. The Board directs:

- EPGI, EPTI and TransAlta to refile their Applications using 1 January 1999 actual plant balances, accumulated depreciation and capitalization.
- EPGI and EPTI to incorporate all corrections and adjustments listed in Exhibit 8 in their refiling.
- TransAlta to incorporate all corrections and adjustments listed in Exhibits 59, 75 and 169 in their refiling and the correction noted in TransAlta's letter to the Board dated 29 October 1999.
- AE, EPGI, EPTI and TransAlta to refile their Applications to comply with the findings of the Board in this Decision.

The Board considers it important that the modeling runs and other matters are carried out as directed to ensure prices and tariffs are set at the appropriate level.

The Board directs that the refilings be in sufficient detail to clearly demonstrate compliance with the Board's findings. The refiling should capture all of the intricate interrelationships among the generation forecast, the Utilities' revenue requirements and prices and tariffs.

The Board directs the Utilities to circulate the refilings to all registered parties in this proceeding for the sole purpose of ensuring that the refilings conform to the findings of the Board. The Board will provide Intervenors with an opportunity to comment on the refilings. In the event that the refiling is not in sufficient detail to clearly demonstrate compliance with the Board's findings, the Board may allow an Information Request and Response process.

[2] ENMAX Argument, p.13
[3] Trans Alta Reply, p.10

After the Board is satisfied that the refilings comply with the findings of the Board, the Board will issue its Order finalizing 1999 and 2000 reservation prices, unit obligation prices, transmission tariffs and TransAlta's DISCO revenue requirement

The timetable for the above-noted process is:

- Utilities refilings: On or before 16 December 1999.
- Comments from interested parties: On or before 23 December 1999.
- Utilities reply (if necessary): On or before 7 January 2000.

(c) Effective Period for Tariffs

During the course of the 1996 GTA, the following issues were raised with respect to prices and tariffs:

- The period of time during which GENCO, TRANSCO and DISCO prices and tariffs should have effect.
- Whether the Board on its own motion or on the motion of an interested party has the jurisdiction to review prices and tariffs during the period that the rates are intended to have effect.
- If the Board does have the jurisdiction, what criteria should the Board utilize in determining whether a review should take place?

These issues arose because provisions in the EU Act with respect to the review of a utility's rates differ from those in the *Public Utilities Board Act* (PUB Act). The EU Act provides as follows:

> **57(1)** Unless section 20 of the *Alberta Energy and Utilities Board Act* applies, no order of the Board approving a tariff shall be reviewed, rescinded or varied during the period in which the tariff is intended to have effect, except in accordance with this section.
>
> **(2)** Any person affected by an order approving a tariff may ask the Board to review the order
>
> > **(a)** if the terms or conditions provided by the tariff for discontinuing the rates have been met and the order provides for a review under this section in those circumstances,
> >
> > **(b)** if the owner of the electric utility or the Transmission Administrator has breached in a material manner a term or condition of the tariff,

> **(c)** if, since the date of the order, circumstances have changed in a substantial and unforeseen manner that renders the continuation of the tariff unjust and unreasonable, or
>
> **(d)** if, in the Board's opinion, the order contains an error of fact or law, provided that the request for a review on that ground is filed with the Board not later than 90 days after the making of the order.
>
> **(3)** Sections 38(1), 39, 56, 77(1) and 79 of the *Public Utilities Board Act* do not apply to the review of an order by the Board under subsection (2).

In contrast, sections 81 and 83(1) of the PUB Act authorize the Board to fix just and reasonable rates based on a test period that may stay in effect beyond the test period. The rate-setting process is initiated when a utility applies to the Board to fix rates or when the Board decides that a review is appropriate. Under section 86(1) of the PUB Act, the Board is required to review rates at least once in every three years. A person or municipality whose interests are affected or are likely to be affected by the results of the review are entitled to obtain the results from the Board. In addition, under section 72 of the PUB Act, a review can be conducted on the application of an owner of a utility, a municipality or a person having an interest in the matter in respect of which the application is made if the applicant is able to make it "appear to the Board...that there is reason to believe that the tolls demanded by the owner of a public utility exceed what is just and reasonable...."[4]

Sections 38(1), 39, 56, 77(1) and 79 of the PUB Act respectively detail the Board's general powers to conduct an inquiry into any matter within its jurisdiction; to exercise its jurisdiction or powers from time to time or at any time as required; to review, rescind or vary any order or decision made by it; and to investigate any matter concerning a public utility.

The Board, in Decision U97065, found that the determination of the effective period of the tariffs is a matter left to the discretion of the Board. The Board found as follows:

> The EU Act establishes a regulatory framework that provides for negotiated settlements and incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between an electric utility and its customers in any tariff that Board may approve. The Board notes that parties generally held the view that the benefits of negotiated settlements and incentive rates are more likely to be realized through multiple-year rates rather than rates of shorter duration. To facilitate that end, several steps were taken in the EU Act to provide for multi-year tariffs and greater certainty that tariffs once approved by the Board would remain in place over their life. Sections 49(3) and 57(1) of the EU Act, respectively, refer to rates intended to have effect over a period or during

[4] Section 72, PUB Act

> a period; however, the EU Act is silent on the appropriate life of a rate period, leaving this determination to the discretion of the Board. In addition, the three-year review period provided for in the PUB Act no longer applies to electric utilities and the basis upon which a person affected by an order of the Board approving a tariff may base an application for review is narrowly circumscribed. These changes are consistent with the scheme for incentive rates anticipated under the EU Act. Once approved, rates are expected to be in effect for a period of time of sufficient length to allow the incentives built into the rates to be achieved absent the triggering of one of the review criteria. The criteria upon which a person affected by an approved tariff may base an application for review have been narrowed in order that it be more difficult for rates to be reviewed within an approved rate period thereby providing greater certainty for the incentives in the rates to mature over the life of the rate period.[5]

The Board exercised its discretion in the 1996 GTA by finding that the prices and tariffs should only remain in effect for the 1996 calendar year.

The Board also made the following finding respecting its jurisdiction to review and the criteria for review:

> While the Board's power to review rates pursuant to the PUB Act are no longer applicable to electric utilities, the Board has the power to review tariffs approved under the EU Act on its own motion pursuant to section 10(2) of the *Alberta Energy and Utilities Board Act*, which states:
>
> > **10(2)** In any case where the ERCB or the PUB or the Board may act in response to an application, complaint, direction, referral or request, the Board may act on its own initiative or motion.
>
> In exercising this power, the Board is of the view that its discretion is confined by section 57(2) of the EU Act. This is a measure which also contributes to greater certainty that rates will remain in place over the effective rate period.[6]

The issue of the effective period of tariffs has also been raised in this proceeding.

Position of IPCAA

In Decision U97065, the Board examined the question of the period of time during which the approved prices and tariffs should remain in effect; the question having arisen from the apparent differences between the provisions of the EU Act and those of the PUB Act. The Board ultimately decided that, for various reasons, it would not approve rates extending beyond 1996.

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[5] Decision U97065, p.64-65

[6] Decision U97065, p.65

IPCAA submitted that most, if not all, of the factors that led the Board to the conclusion that the approved rates should be in effect only during the test year are present in this proceeding. The Board should therefore expressly state in its Decision that the approved tariffs are to remain in effect only until 31 December 2000.

Board Findings

The Board notes that the Applicants generally referred to the proposed prices and tariffs as being applicable to the test years 1999 and 2000. The Board also notes that no interested party other than IPCAA raised this issue in argument and none of the parties replied to IPCAA's argument.

The Board remains of the view that the determination of the effective period of the tariffs is a matter left to the discretion of the Board.

The Board considers that GENCO prices and tariffs should only remain in effect until 31 December 2000 since Parts 4 and 5 of the EU Act cease to apply to regulated generating units on 1 January 2001.[7]

The Board also considers that TRANSCO tariffs should only remain in effect until 31 December 2000 since experience with the Transmission Planning Guidelines and the pending legislative enactment warrant a further review of TRANSCO tariffs for the period beyond 31 December 2000.

Further, the Board considers that DISCO tariffs should only remain in effect until 31 December 2000 since the scheduled implementation of customer choice and the Distribution Access Tariff effective 1 January 2001 will render 1999 and 2000 DISCO tariffs obsolete.

For all of the above reasons, the Board agrees with IPCAA that GENCO, TRANSCO and DISCO prices and tariffs should only remain in effect until 31 December 2000. The Board directs AE, EPGI, EPTI and TransAlta, in their refilings, to clearly state that their prices and tariffs are in effect on a final basis only until 31 December 2000. The Board recognizes that there will be further adjustments due to the disposition of deferral accounts. The Board directs AE, EPGI, EPTI and TransAlta to file an application for rates effective 1 January 2001 if such new rates require Board approval.

(d) Interest on Rate Adjustments

Introduction and Implementation

The payment of interest on over-collections or under-collections by the Utilities has been questioned by some Intervenors. The Board issued a draft Guideline on when interest may be

[7] EU Act sections 45.95(2) and 45.92(2)

paid on under-collections or over-collections. The finalized version of the Guideline is expected to issue shortly.

Position of the Intervenors

IPCAA stated that each of the applicants should be required to pay interest on any amount that the applicant is ordered by the Board to refund to customers. Interest should be payable at a rate equal to the relevant applicant's approved rate of return on rate base and should be payable on all outstanding amounts until the refund has been completed. IPCAA recommended that the interest paid should be a shareholder expense not recovered from customers. IPCAA also noted that by the same token, if the result of the Board's decision is a revenue deficiency then the utilities should be permitted to collect the appropriate amount of interest from customers.

IPPSA/SPPA stated that it supported IPCAA's position with respect to interest on rate adjustments. IPPSA/SPPA argued that without an interest policy there continues to be an incentive for utilities to over-forecast and over-collect from customers. IPPSA/SPPA considered that the reduced financing costs which ensue from over-collections are a direct benefit to shareholders at the customer's expense.

Board Findings

The Board notes that the extent to which there are over-collections or under-collections for each of the Utilities will not be known until the Utilities complete their refiling. Therefore the Board will consider the matter of interest when it reviews the refilings. The Board expects that any determinations that it makes on interest will be in keeping with the Board's Guideline on interest.

Part 1 – GENERAL

2. RESTRUCTURING ISSUES

(a) Legislative Framework

The proclamation of the EU Act in May 1995 signaled a movement away from the traditional cost of service/rate base regulation of the Alberta electric industry to a competitive market for electricity and, thus, represented a turning point in the evolution of the electric industry. The EU Act reflected broad stakeholder consensus with respect to how restructuring and reform of the electric industry should proceed. As a matter of expediency, some issues were deferred for resolution at a later date. Therefore, the EU Act represented the start of the restructuring and reform process. After a few years of learning and experience, the industry-restructuring framework established in the EU Act in 1995 was expanded via amendments to the EU Act in April 1998.

This section describes pertinent elements of Alberta's electric industry restructuring framework established by the EU Act and its 1998 amendment. It is intended to provide a contextual background so that some of the issues and concerns raised during this proceeding can be better appreciated and understood.

(1) The *Electric Utilities Act* (1995)

From the fall of 1993 through to the spring of 1995, the Alberta Government held extensive consultation with electric industry stakeholders. This consultation resulted in a consensus agreement with respect to principles on which restructuring and reform of the Alberta electric industry would proceed. This agreement was embodied in the EU Act and established a broad framework for restructuring and reforming the electric industry. Regulations were used to flesh out concepts contained in the EU Act.

The key purposes of the EU Act were:

- To establish an efficient market for generation based on fair and open competition.
- To ensure that the benefits and costs associated with existing, regulated generating plants continue to be shared equitably by current and future consumers throughout the province.
- To ensure that investment in new generation is guided by competitive market forces.
- Where regulation is still necessary, to minimize its cost and provide incentives for efficiency.

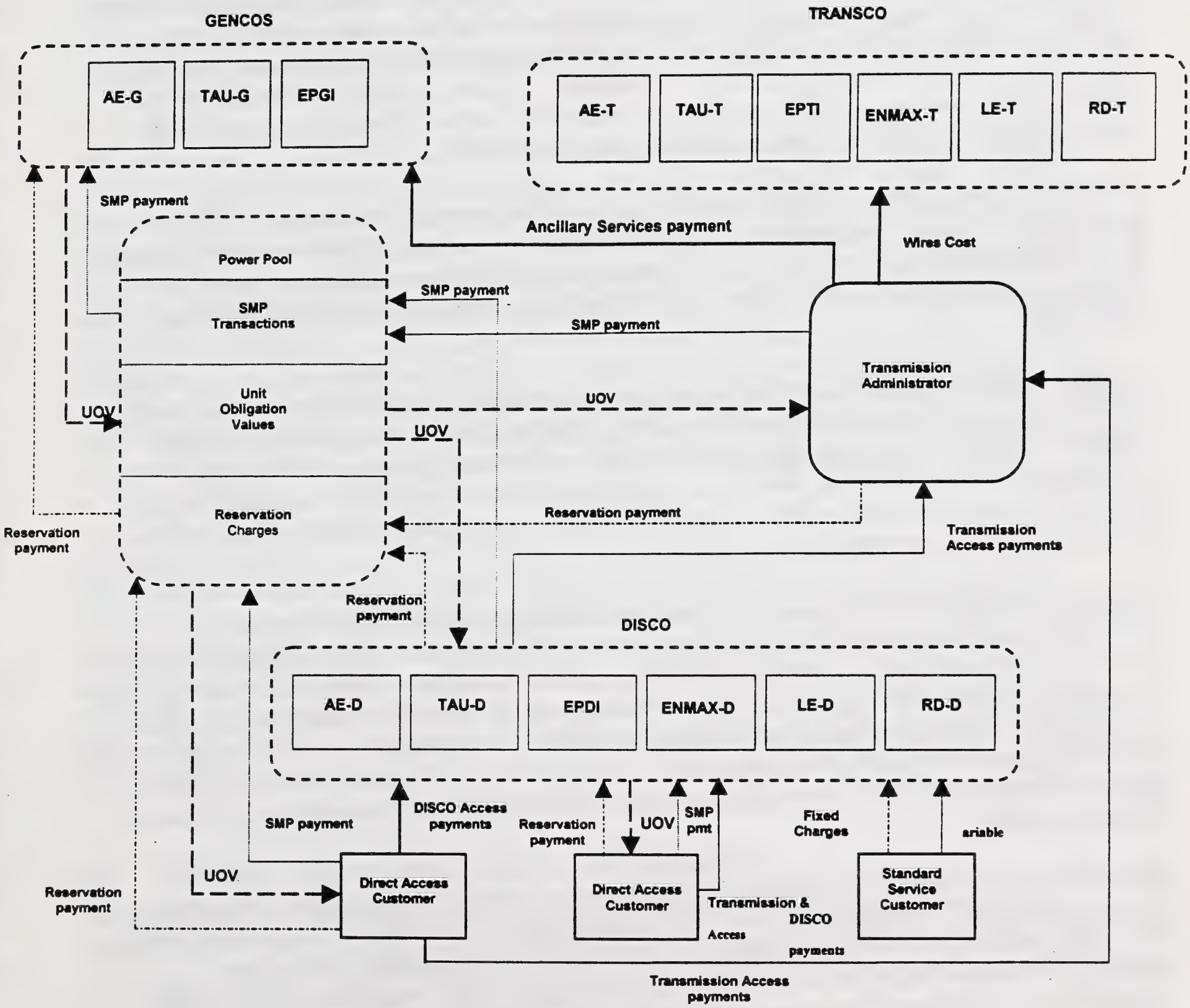
The industry-restructuring framework embodied in the EU Act was built around the following:

- An open-access Power Pool through which electricity is competitively bought and sold.
- Functional separation of the integrated Utilities into generation, transmission, and distribution functions for accounting and regulatory purposes.
- A TA who coordinates the transmission grid such that it functions as a single provincial system.

2. RESTRUCTURING ISSUES
(a) Legislative Framework

- Cost recovery of existing generation and price certainty for consumers' existing load through legislated financial hedges of the pool price.
- Market forces would determine new generation.

The diagram below, which was taken from the cover page of the evidence presented by Drazen Consulting Group, Inc. (DCGI), shows the main elements of the restructured industry by function and identifies some of the major players. It also provides a high level overview of how the legislated hedges work.



2. RESTRUCTURING ISSUES
(a) Legislative Framework

Legend		
	AE – ATCO Electric Ltd.	LE – Lethbridge
	EPGI – EPCOR Generation Inc.	RD – Red Deer
	EPTI – EPCOR Transmission Inc.	UOV – Unit Obligation Value
	EPDI – EPCOR Distribution Inc.	SMP – System marginal price
	TAU – TransAlta Utilities Corporation	

(A) Competitive Market for Generation

The structure established by the EU Act did not affect the physical nature of electricity delivery nor did it require the integrated Utilities to divest themselves of their assets. However, the functions of generation, transmission, and distribution were separated for accounting and regulatory purposes. Section 48 of the EU Act requires an electric utility to maintain separate books, records, and accounts for generation, transmission, and distribution and to submit an annual report of finance and operations in this form to the Board.

To ensure that government-owned participants do not have an unfair advantage, the EU Act establishes conditions under which municipalities may own an interest in a new generating unit for sale of power into the Power Pool. The conditions prevent any tax advantage, subsidy or financing advantage or any other benefit as a result of the generator's association with the municipality.

One of the corner stones of the new structure is an independently operated open access Power Pool through which electricity is bought and sold in Alberta. Section 13 requires all energy entering or leaving the Alberta interconnected system to be traded through the Power Pool of Alberta (Power Pool). The pool serves as an hourly spot market for energy. A single price is declared for each hour based on the prices of generation, imports, and curtailable loads offered to the Pool to meet the demand in that hour.

Section 11 provides for an independent Power Pool Administrator who is responsible for operating the pool and for financial settlement. Section 12 establishes a System Controller who, under the auspices of the Power Pool manages the real-time operation of the system. The System Controller manages dispatch, gives direction to the owners of transmission facilities as required for the safe, reliable and economic operation of the AIS, and ensures provision of adequate levels of system support services as determined by the TA. At the outset, TransAlta assumed the role of System Controller until such time as the Power Pool had the necessary resources to perform this function directly.

Governance of the Power Pool and the System Controller was to be accomplished through the statutory creation of a stakeholder Power Pool Council (section 7 of the EU Act). In June 1995, a 10-member council, representing utilities and organizations in the electric industry, was appointed to establish rules and ensure that the Power Pool operated according to its mandate. Section 16 of the EU Act allows complaints regarding the workings of the Power Pool to be

made to the Board. However, the Board is prohibited from hearing a complaint unless a negotiated settlement has been attempted in good faith and this effort has failed.

On 1 January 1996, the Power Pool of Alberta commenced operation with about 30 participants consisting of utility and non-utility generators, importers and exporters, and distribution companies.

Another critical element to the establishment of a competitive generation market is the provision of non-discriminatory transmission system access to the Power Pool to allow wholesale energy transactions to occur. Section 24 of the EU Act requires the Transmission Administrator (TA), the sole provider of system access service, to afford all Power Pool participants with a reasonable opportunity to obtain system access service. Section 21 of the EU Act provides for the appointment of the TA.

The TA oversees the use of the transmission system by buyers and sellers to ensure fair rates, non-discriminatory access for all market participants and the safe, reliable operation of the system. The TA contracts with the owners of facilities to provide transmission services and ensures the necessary ancillary and support services. In addition, subject to regulatory approval by the Board, the TA establishes tariffs to recover system access costs from distributors and generators. The EU Act requires that "postage stamp" rates be set for load customers, section 27(2)(b) stipulates that the rate set out in the tariff must not be different for owners of electric distribution systems as a result of the location of those systems on the transmission system. The Board proceedings in 1996 marked the first time that separate transmission system tariffs were filed with the Board for approval. The results of the Board's consideration are contained in Board Decision U97065 regarding the Utilities 1996 Electric Tariff Applications, issued 31 October 1997.

The three main Utilities and the City of Calgary (Calgary) agreed, via a shareholders' agreement, to transfer the management of their transmission facilities to the Grid Company of Alberta (Gridco). On 1 January 1996, with oversight from a stakeholder-governed Electric Transmission Council, Gridco assumed the role of TA for the first two years of the restructured system's operation pending the appointment of an independent TA. The Government subsequently embarked on an open process to select an independent TA that had no affiliation with any of the market participants. The search resulted in ESBI Alberta Ltd. (EAL) being appointed as the TA in June 1998.

(B) Sharing of Costs and Benefits of Existing Generation

Under the EU Act, all consumers share the costs and benefits of the generation facilities in existence in 1995 when the EU Act was passed. A notable exception to this relates to electric energy produced in the service area of the City of Medicine Hat which, pursuant to section 2 of the EU Act, is exempted from the operations of the EU Act.

2. RESTRUCTURING ISSUES
(a) Legislative Framework

The sharing of the costs and benefits of existing generating facilities is accomplished through legislated financial arrangements (hedges) between distributors, on behalf of their customers, and the owners of existing regulated generation. These hedges protect both customers and utilities in the short run. Customers are shielded from pool prices greater than the cost of power from existing regulated generation for a large portion of their current load requirements. Likewise, Utilities are protected from the risk of investment in their existing generation facilities becoming stranded. Entitled Distribution Systems manage the legislated financial hedges on behalf of all their customers. The specifics of the hedges are determined through a combination of regulations and Board decisions.

In essence, the system aims to ensure that distributors pay a price for existing units which is close to the variable costs of generation for a unit obligation amount and, in addition, pay reservation payments to cover the fixed costs of existing generation. In return for this coverage, the regulated generators are obliged to provide a hedge, or obligation value, for the hourly pool price to distributors. The obligation value is the difference between the pool price and the unit obligation price set by the Board multiplied by the unit obligation amount. The net cost of wholesale power to the distribution company is therefore the Pool price, plus the reservation price, less the obligation value. Further information on how the hedges work and on unit obligation prices can be found at Part 1–General of Board Decision U97065 regarding the Utilities 1996 Electric Tariff Applications, issued 31 October 1997.

The costs for new generation brought on line after the passage of the EU Act are not shared or cost of service regulated (Note that construction and siting of new facilities still require Board approval). The addition of new generation facilities is now based on market considerations.

(C) Regulation

The EU Act explicitly removes existing legislative barriers to the development of incentive or performance based regulation. Section 51 requires that tariffs filed for Board approval provide for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the electric utility and customers.

Utilities and consumers can negotiate the settlement of tariffs or any other issue that is within the ordinary jurisdiction of the Board and file the settlement with the Board for approval (section 67 of the EU Act). Utilities and Intervenors are encouraged to reach negotiated settlements as an alternative to full public hearings. Section 65 of the EU Act requires the Board to recognize or establish rules, practices and procedures that facilitate the settlement of an issue. In 1998, the Board issued its Negotiated Settlements Guidelines.

While the EU Act provides for reduced regulatory oversight it certainly does not spell the end of cost-of-service regulation in the Alberta. The Board remains responsible for examining and approving, inter alia:

- The cost of existing generation until 31 December 2000 when the PPAs come into effect;
- The TA system access tariffs; and
- The costs incurred by investor-owned distribution companies, and the retail rates they charge to consumers.

As noted previously, aspects of the legislated hedges are to be approved by the Board and will continue until existing generating units are deregulated on 1 January 2001.

The Board continues to review applications to build generating plants and transmission facilities for compliance with environmental and planning requirements. However, it will no longer assess the need for and timing of new generation facilities. Instead, decisions to build new generating capacity will be made on a purely commercial basis.

Transmission and distribution wires systems continue to be regulated since they are considered to be natural monopolies. Before new transmission facilities can be built it must now be shown that they are needed for the present and future public convenience. Additionally, section 5 of the EU Act preserves the notion of distribution service areas.

(D) Areas Requiring Further Work

While significant building blocks were laid, it was generally recognized that more work had to be done before the transition to a fully competitive market could be achieved. In several areas, the EU Act only laid the groundwork for elements of the stakeholder consensus agreement.

Section 41 and 42 of the EU Act established a framework for the removal of existing generation from regulation; details on the section 42 regulations were to be worked out between the Alberta Department of Resource Development (DRD) (formerly the Alberta Department of Energy) and stakeholders during 1996. Customer choice remained to be studied, with the understanding that further analysis would be needed before selecting an option for end-user choice of pricing arrangements.

(2) Bill 27/Amendment to the *Electric Utilities Act* (1998)

As noted previously, considerable work still needed to be done to complete the restructuring and reform of the electric industry. Using the experience it gained with industry restructuring following the implementation of the EU Act on 1 January 1996, the DRD worked with stakeholders to clarify a vision for the future of the electric industry. The DRD and stakeholders also identified solutions and laid out a timetable for achieving that vision.

This activity culminated in 1998 with the drafting of Bill 27 that proposed significant amendments to the EU Act. The focus of Bill 27 was on deregulation of existing generation, increased competition, and customer choice. The overarching objective was to complete the

transformation of the electric industry into a competitive and market-driven structure. Bill 27 was passed and the proposed amendments, which were incorporated into the EU Act, came into force as of 30 April 1998. The amended EU Act requires that, by 1 January 2001, all generation is to be (cost) deregulated and full retail competition of electricity is to begin.

Following are the main elements of the amended legislation:

- By 2001, long-term power purchase arrangements will replace the current mechanism for capturing the costs and benefits of existing generation. An open auction of the contracts will increase competition by diversifying the number of sellers in the Power Pool through which all electrical generation is bought and sold in the province. These contracts do not require divestiture of assets.

- A financial Balancing Pool will net the proceeds from the auction of the power purchase arrangements. These proceeds, which will reflect the value of the existing, low-cost generation, will be distributed to customers. All customers across the province, old and new, will share in the low cost of generation built under regulation.

- Competition will be fostered through development of a level playing field for industry participants. As part of this process, the Power Pool will be governed independently rather than by stakeholders. The Power Pool Council will be given greater authority to monitor markets, investigate complaints and resolve disputes.

- A framework will be put in place for implementation of customer choice by 2001. Under this process, customers will be able to choose between competing retailers of electricity and related services.

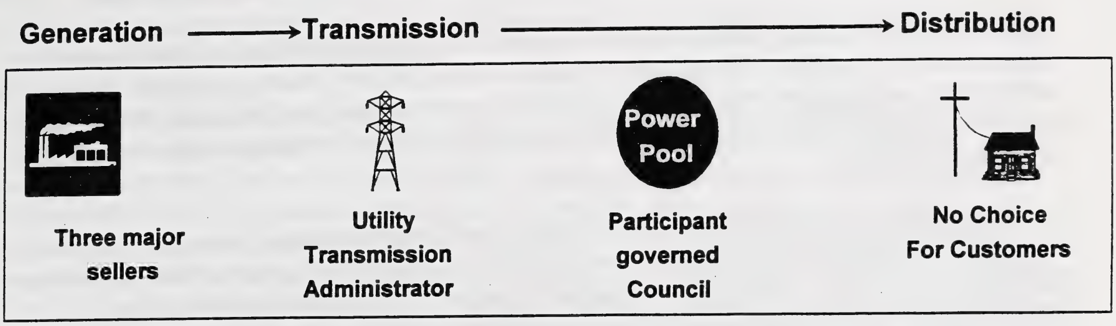
- Regulations made under the original EU Act were brought into the legislation.

As was the case with the original EU Act, a substantial number of regulations are required to flesh out and supplement the framework established by the 1998 amendments.

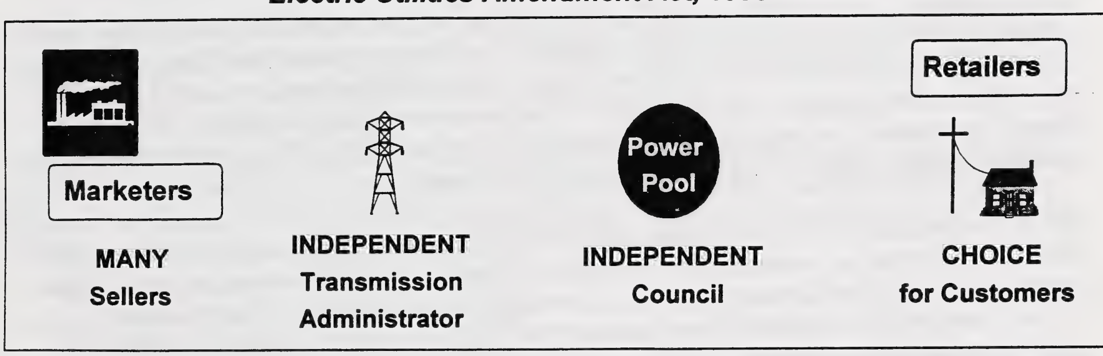
The diagram below (which was taken from a DRD presentation) pictorially depicts how the industry will change when all of the objectives of the amended EU Act are achieved.

2. RESTRUCTURING ISSUES
(a) Legislative Framework

Electric Utilities Act, 1995



Electric Utilities Amendment Act, 1998



(A) Deregulation of Generation

Following implementation of the EU Act in 1996, a key issue that emerged was the potential market power of the three main generation companies. To address this matter the DRD retained London Economics, Inc. to develop alternative options for the mitigation of market power in the Power Pool. It was intended that the results of that study would guide legislative and regulatory changes.

Based on the findings of the London Economics study, the DRD decided that competition in the offering of electric energy to the Power Pool would increase if the number of participants offering supply into the Power Pool were increased. Increased competition would be to the ultimate advantage of consumers. This increase would be achieved by transferring to third party marketers the right to offer the power plants' output into the Power Pool and to receive the Power Pool revenues. The transfer of offer rights would be accomplished by means of long-term power purchase arrangements (PPAs) between the marketers and the owners of the regulated generating facilities. Under the terms of the PPAs, the marketer would have an obligation to pay

the owner of the power plant its fixed and variable costs, including a reasonable return on assets. The three generating Utilities would continue to own and operate their respective plants.

Through an open auction process, the PPAs would be sold. Successful buyers would have the right to market the output of the generating units to which the PPA relates. Accepted auction bids both positive and negative would flow to a financial account called the Balancing Pool. Any aggregate surplus or deficit in the Balancing Pool would be transferred to consumers through a rate reduction or levy.

The arrangements for establishing the PPAs and the auction are set out in Part 4.1 of the EU Act. Additional clarifications regarding PPAs are contained in the Power Purchase Arrangements Regulation AR 170/99, which was promulgated in August 1999. Rules respecting the establishment and operation of a Balancing Pool by the Power Pool Council are contained in the Balancing Pool Regulation AR 169/199.

An Independent Assessment Team (IAT), with its scope and duties set out in the EU Act, was required to accomplish two major tasks: assessment and determination of the PPAs, and design of the auction process. On 6 July 1998, the Minister of Energy appointed PriceWaterhouseCoopers (PWC) and Charles River Associates (CRA) as the IAT. PWC was charged with making the assessment and determination of the PPAs. CRA was responsible for making recommendations on the design of the auction process.

The EU Act requires the IAT to first assess an owner's proposals respecting the commercial terms for a PPA over a generating unit's base life and any proposed life extension period. Then, it must determine PPAs for each regulated generating unit listed in Part 1 of the Schedule in the EU Act. Section 45.9 of the EU Act requires the IAT to file a report containing the PPAs and other determinations for approval with the Alberta Energy and Utilities Board. The IAT report was filed with the Board on 9 July 1999.

Section 45.91 of the EU Act provides limited grounds on which the PPAs and other determinations made by the IAT may be appealed to the Board. Following the filing of the IAT report, many requests for variance were made. After considering the requests, the Board held a hearing from 13 October 1999 to 20 October 1999 to review a few specific issues that were raised. Argument and reply were filed on 1 November 1999 and 5 November 1999. A Decision from the Board is pending. Once approved by the Board, the PPAs, which will replace the current legislated financial hedges, will become effective on 1 January 2001 and will be in effect for a maximum of 20 years.

Although the Board is not involved in the auction process, it is currently envisaged that the auction of the PPAs will take place in mid 2000. Section 45.93(2) of the EU Act requires the IAT to make recommendations respecting the design of the auction to the Minister. CRA submitted the draft recommendations to the Minister in early September 1999.

(B) Increasing Competition

The principal measures for increasing competition were to change the governance of the Power Pool and to improve market surveillance.

Section 7 of the EU Act now requires the Minister to appoint members to the Power Pool Council who are independent of persons having a material interest in the Alberta electric industry. The Power Pool was given additional responsibilities and authority for surveillance of the electricity market, investigation of alleged misconduct or breaches of the rules, and imposition of monetary penalties or sanctions against those who violate these rules. Primary responsibility for discharging these duties will rest with one of the Council members designated as the Market Surveillance Administrator. In May 1998, the Minister of Energy approved the appointments of three independent Power Pool Council members, one of whom was appointed Market Surveillance Administrator.

With the introduction of section 9.8 of the EU Act, decisions of the Power Pool Council can now be appealed to the Board. This is in addition to the Board's complaint authority respecting the workings of the Power Pool pursuant to section 16 of the EU Act.

The Direct Sales Regulation AR 180/99 and associated Power Pool rule changes were introduced in 1999 to help achieve the goal of increasing competition in the energy market. Allowing pool purchasers to contract directly with the independent power generator of their choice will encourage independent power producer activity.

(C) Customer Choice

When full retail competition is introduced in January 2001, electricity consumers will have the choice to select any retail service provider they wish. Small and residential consumers will have access to choice starting in 2001. Additionally, for a five-year period starting in 2001, small and residential consumers will have the option of continuing with their current service provider and receiving a regulated rate, or making new arrangements with a service provider. Section 31.995(1)(k) of the EU Act provides as follows:

> 31.995(1) The Minister may make regulations
>
> ....
>
> (k) respecting the holding of a hearing by the Board before March 15, 2000, or any later date, relating to the approval of a stable rate tariff that sets a stable rate for customers for the period beginning on January 1, 2001 and ending at 12 midnight on December 31, 2005 and providing for that rate to be negotiated by settlement under Part 6.

The principles underlying the measures in the EU Act and Regulations for achieving customer choice are:

2. RESTRUCTURING ISSUES

(a) Legislative Framework

- Markets for retail services are to be shaped solely by competitive forces and are not to be distorted by unfair advantages arising from ownership or incumbency.
- The responsibility for the costs of the existing generating, as well as the benefits of the low-cost power from that generation, are allocated to be directly to end-use customers.
- Residential and other small customers who desire a regulated rate are assured that it will be provided by their traditional electric distribution utility retailer during the transition to a competitive generation market. Section 31.991(1)(e) requires wire service providers to "act as retailers to customers who choose to pay a stable rate for electricity for the period beginning on January 1, 2001 and ending at 12 midnight on December 31, 2005 in accordance with the regulations."

Distribution Regulation AR 168/98 required direct access tariffs to be approved and available by 1 April 1999. With the Board approval of direct access tariffs in 1999 certain large customers with time-of-use meters could opt to have the hourly pool price directly reflected in their rates.

Starting 1 January 2001, all customers will receive the right to choose their retailer of electricity and other related services they wish to purchase. At the same time, retail services, which may include rates and pricing arrangements and energy management services, will be "unbundled," meaning that they can be offered and priced separately by competing retailers. At the same time, retailers and other industry participants will be licensed and subject to standards and certification.

The existing distribution Utilities will continue to provide connections to customers, and build and maintain local distribution wires. Access to distribution wire and tariffs for the use of these wires will be regulated by the Board, either directly or through a complaint process, as prescribed in Distribution Regulation AR 168/198. (Note that as provided for in section 31.3 of the EU Act, the distribution tariffs referred to in the Distribution Regulation do not apply to the City of Medicine Hat.) All other distribution services will ultimately become part of the competitive marketplace. There will be a transition period during which the regulated Utilities will continue to provide some retail services such as provision of meters and meter reading.

During the transition period, existing distribution Utilities will be required to form separate arms-length companies (i.e., retailers) to offer traditional retail services to customers in their service area. The existing distribution Utilities will be required to offer residential and other small customers in their current service area a Regulated Rate Option through their affiliate retailer during a five-year transition period. Rules governing the conduct of these companies will address a level playing field exists between retailers competing to offer services in this field. These rules will include sharing of information about energy use patterns so that new retailers can develop appropriate new products and services.

(D) Regulation in the Restructured Industry

Restructuring and reform of the electric industry resulted in the following regulatory proceedings:

- The 1996 Utilities General Tariff Applications to set the new tariffs under the new structure, including the setting of unit obligation prices and the aggregate reservation price.
- TA system access tariff applications, commencing with the Gridco application in 1996 and continuing with EAL's 1998 and 1999/2000 applications.
- Direct access tariffs for customers having time of use meters, starting in 1999.
- The hearing to consider requests for variance of the PPAs and other determinations of the IAT.
- The distribution access tariffs for all wire service providers (to be held in 2000).
- The stable rate hearing (to be held in 2000).

The regulatory changes described in section 2(a)(3) above continue to be applicable. Some additional elements are discussed below.

With respect to generation, the Board will continue to regulate the cost of existing generating units until they are replaced by PPAs on 1 January 2001. In that regard, this proceeding marks the last time an integrated utility general tariff application will be considered and ruled on by the Board. Additionally, the Board will continue to have responsibility for reviewing and approving power plants with respect to environmental and siting matters. Appeals of Power Pool Council decisions and complaints about the workings of the Power Pool will also have to be considered by the Board. The Board is also required to deal with recommendations of the Market Surveillance Administrator which have been referred to the Board by the Power Pool Council.

Transmission and distribution wire systems will continue to be regulated. The need for new transmission facilities or amendments to existing facilities will have to be clearly established by new and existing TFOs before the Board can approve them. The tariffs that transmission facility owners charge the TA for the use of their wires together with the TA's system access tariffs require Board approval. Additionally, the TA may also apply for approval of contracts for system support services.

The EU Act and Distribution Regulation AR168/98 require the Board to now regulate distribution access tariffs either directly or on a complaint basis. The regulated rate tariff for the transition period from 2001 to 2005 will also have to be approved by the Board. Load profiles required for financial settlement at the retail level will be filed with the Board and will be regulated on a complaint basis.

(b) Relationship Between GTAs and Post 2000 PPA Regime

The IAT, pursuant to the EU Act, determined PPAs applicable to existing generating units that were built under regulation and filed the PPAs with the Board for approval. The cost of these regulated units for 1999 and 2000 are dealt with in the GTAs by the Utilities. PPAs are long-term arrangements that indicate the quantity of electricity to be provided from each unit, performance expectations for each unit and fixed and variable costs to be paid to the owners of the generating units. When approved by the Board, these arrangements will start on 1 January 2001 and run for a maximum of twenty years. The advent of the PPAs will effectively end cost of service/rate base regulation for generating plants in Alberta as it is known today.

To ensure a smooth and fair transition from a regulated environment to a PPA regime, participants submitted that the decisions arising from the GTAs currently before the Board must be coordinated with the PPAs determined by the IAT. There was also concern about how credits and charges not incorporated in the PPAs, such as balances in deferral accounts or reserve accounts, would be treated post year 2000.

Position of TransAlta

TransAlta submitted that, given the two processes have been conducted in isolation from one another, the Board must ensure that there is a smooth transition or reconciliation between the decisions made in these GTA proceedings and the PPA determinations. Coordination of the Board's Decision and the IAT process is essential because, if matters were allowed to "fall between the cracks," this would disadvantage both Utilities and customers. As noted by Mr. Way, TransAlta's approach has been:

> ...to try and encourage that there would be a process at the end. It is probably more important the process be focused on the PPAs and the opening balance there, but I don't believe we have had any incentive to do anything other than promote that there be a process to reconcile the closing and opening balances between the two processes.[8]

Mr. Way also stated:

> ...so in total for generation, we do expect there not to be a bump in the road, if you like, between 2000, December 31, and January 1 of 2001 when the PPA's kick in. To be honest, we are not quite sure how that bump will be avoided at this point, but we think it is important that the two fit together.[9]

To illustrate how the two processes are linked and the type of reconciliation that might have to occur, Mr. Way cited an example. He first postulated that the Board, as a result of its

[8] Tr. p.1728
[9] Tr. p.1727

deliberation on the GTAs, might decide not to allow a forecast 1999 capital expenditure that would have resulted in operating savings beyond 2000. He then went on to submit that, given the disallowance, the reasonable thing to do would be to adjust the operating costs in the PPA. Mr. Way concluded with the general proposition that, if the Board alters TransAlta's Generation costs as filed in the Application, fairness dictates that the change should be reflected in the PPA for the period 2001 and beyond.

While it recognized the need to harmonize the two processes, TransAlta was unclear as to how continuity would actually be achieved. Mr. Way articulated this as follows:

> At this point, I'm not sure what the mechanism is. We just believe there should be some sort of reconciliation or some process anyhow to ensure the two are reasonably consistent.[10]

In response to the FIRM Customers suggestion that cost increases (relative to the previous three years) in TransAlta's Application represent an attempt by TransAlta to position itself favorably for the post PPA period at customers' expense, TransAlta submitted that the record simply does not support this assertion.

With respect to ENMAX's proposal that TransAlta and EPGI's inventories be set to zero as at 31 December 2000 and the resulting mid year calculation of working capital be adjusted to reflect those balances, TransAlta submitted that this notion is unreasonable and should be rejected. By way of explanation, TransAlta stated the concept of using mid year balances is predicated on the assumption that the utility is a going concern and there will be varying balances in any given account throughout the year. These balances would effectively be smoothed out by using a mid year balance concept. TransAlta argued that the transition to the PPA regime should not create a bump in costs due to an artificial lowering of costs in 2000 with an offsetting increase in costs in 2001.

TransAlta also pointed out that ENMAX noted in its argument, "the Board also recognized that inventories such as emergency coal are in place to cover the risk of time it would take to rectify down times under certain circumstances." TransAlta submitted that this risk does not go away on 31 December 2000 with the transition to the PPAs and that ENMAX's proposal should also be rejected on that basis.

Position of the FIRM Customers

The FIRM Customers expressed the view that, while the Board's mandate is to establish revenue requirements for the test years, regard must be given to the future direction of the industry after 1 January 2001. Therefore, the Board's Decision respecting the 1999/2000 GTA cannot be made in isolation from the IAT process. The FIRM Customers submitted:

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[10] Tr. p.1727

The Board's determinations for 1999/2000 will have important implications for the IAT process, most particularly from the point of ensuring continuity. Although continuity will affect a wide list of issues, the most significant are, perhaps, 2000 year end balances for gross plant, accumulated depreciation, debt and preferred capital (including embedded cost rates), no cost capital (including deferred tax balance), unamortized deferred expenses and unused capital cost allowance. Of course, these would refer to the generation function of each.

The FIRM Customers also submitted that:

> Throughout this proceeding the Board and customers have been saddled with incomplete information with respect to the forecast ending balances in the generation regulated world of 2000 and the forecast opening balances of the PPA world in 2001. Large write-offs proposed for the 1999/2000 period where assets should reflect longer amortization periods are of particular concern. For instance, TAU is applying to write inventories at plants down to zero when such inventories will still be required, and still have value in, the subsequent PPA world. Further, the write-off of 1500 computers and the High River Service centre in the 1999/2000 period raises questions as to whether these actions are necessary in the period just prior to generation de-regulation.[11]

The FIRM Customers were concerned that TransAlta and EPGI were attempting to include a large number of questionable items in its forecast revenue requirement. In particular, it noted that, in contrast to the previous three years of declining costs, in its 1999/2000 application TransAlta and EPGI were proposing significant cost increase. This, the FIRM Customers asserted, was an attempt by TransAlta and EPGI "to position themselves favourably for the post PPA time frame at customers' expense."[12]

The FIRM Customers were also concerned about the lack of plans or procedures for refunding any large positive balances projected for the end of 2000 back to customers in the post 2001 PPA period.

Because of these concerns the FIRM Customers submitted that:

> ...the important interface between 2000 and 2001 must be detailed in the Board's decision on practically an account by account basis to ensure future customer refunds and entitlements associated with the generation function will, in fact, be addressed by TransAlta.[13]

[11] FIRM Customers Argument, p.72-72, p.144
[12] FIRM Customers Argument, p.144
[13] FIRM Customers Argument, p.145

Position of ENMAX

ENMAX expressed concern that balances in reserve and deferral accounts, which were collected prior to 2001, would not be treated correctly or consistently with how they were originally collected. It noted that after 2000, it is likely that the Board will not have jurisdiction over these accounts and suggested that their disposition to the GENCOs could quite easily go unnoticed. ENMAX was uncomfortable leaving the disposition of these account balances to the Balancing Pool because, at the time of the hearing, there were currently no rules in place governing the Balancing Pool. ENMAX submitted that "all reserve account balances should be reduced to zero at December 31, 2000, and the Board should impose mechanisms to deal with any outstanding credits or charges."[14]

ENMAX noted that through necessary working capital, electric consumers across the province have compensated the applicants for the financing costs of holding inventories of materials, supplies and other assets necessary to the operation and maintenance of the utility system. It also noted that each of the generating utilities would have a different set of customers under the PPA regime than they do under the current regime and that current customers will have no entitlement to inventories after 2000. This gave rise to ENMAX's concern that parties to the PPAs should not benefit from inventories financed by customers. Therefore, ENMAX submitted that:

> ...all EPGI and TransAlta inventories (including emergency coal, live coal and material and supplies) should be set to zero as at December 31, 2000, and the resulting mid year calculation of working capital should reflect those zero balances.[15]

Board Findings

The Board agrees that the GTA and PPA processes should be harmonized so that a smooth transition occurs from the current regulated regime to the PPA regime.

The Board considers that the best way of ensuring that the appropriate level of on-going benefits and costs beyond the year 2000 flow through to the customer is for the IAT to account for these in the PPA determination process. It is the Board's understanding that Board approved forecast balances at 31 December 2000 will be used by the IAT in determining the PPAs. Indications are that all parties also broadly share this view. Board staff will collaborate with the IAT to ensure that Board approved data from the 1999 and 2000 test years is available to the IAT. To assist in this regard, the Board directs the Utilities to include in their refiling a reconciliation schedule, which clearly sets out the differences between the refiling for 1999 and 2000 and what was provided to the IAT for inclusion in the PPA process. The Board is satisfied that through the IAT's "fine-tuning" of the PPAs, continuity between the GTA and the PPA process will be achieved.

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[14] ENMAX Argument, p.15
[15] ENMAX Argument, p.17

Notwithstanding its view that the PPA process should handle the transition from year-end 2000 to 2001, the Board recognizes that there may be some matters such as one-time residual benefits and stranded costs that are better dealt with through the Balancing Pool framework. For example, balances in certain reserve accounts and deferral accounts at the end of year 2000 should be transferred to the Balancing Pool. Accordingly, when it makes its Findings respecting such matters, the Board will direct the utilities to transfer balances from the relevant accounts to the Balancing Pool.

The Board interprets subsections 6(h) and & 7(1)(g) of Balancing Pool Regulation AR 169/99, as providing the Balancing Pool with the authority to accept Board approved credits and charges from the GTA process and to pass these on to the consumers.

The Board, when it addresses continuity matters that effect the period beyond 2000 in this Decision will clearly specify those benefits or costs better included in the PPAs and those benefits and costs better handled through the Balancing Pool.

(c) Relationship Between Regulated and Unregulated Activities

With the changes in the electric industry arising from restructuring, the former integrated utilities are preparing or have begun the process of restructuring their businesses. With these changes there is an increased concern with the relationship between the regulated and the non-regulated portions of the Utility businesses. There is an increased focus on ensuring that non-regulated activities are not gaining advantages or have the opportunity to gain advantages from their regulated affiliates.

Position of IPPCA

IPPCA submitted that one of the Board's tasks in this proceeding is to encourage and assist in the transition to a truly competitive electricity market. IPCAA stated that real competition is still a distant prospect in Alberta and, although the Board cannot create competition, it can facilitate the transition by assuring that the Utilities do not benefit from impeding its development. Relevant issues include the treatment of stranded costs and the recognition of the risk differences resulting from restructuring.

IPCAA submitted that there is now the realization that market power is a major problem. The old view that "competition on the margin" and load growth would solve the problem of market concentration has proved to be incorrect. The Market Surveillance Administrator may never solve the problem and certainly not for 1999 and 2000. IPCAA suggested that the Board must be cognizant of this problem as it considers and decides the matters in this proceeding that relate to the generation forecast.

Position of IPPSA/SPPA

IPPSA/SPPA noted their concern that the Utilities have ignored the spirit and intent of the deregulation process and the underlying principles embodied in the EU Act. IPPSA/SPPA submitted that, should the Board determine that the conduct of the Utilities offends the purposes of the EU Act, or that the conduct seems likely to impede the establishment of a framework that:

- Provides for a competitive Power Pool so that an efficient market for electricity based on fair and open competition can develop, based on non-discriminatory terms; or
- Enables customers to exercise a preference for electricity services in a competitive market

then, the Board ought to provide a remedy. The remedy should be directed toward eliminating the wrongful conduct and ensuring that adequate mechanisms are established to prevent the conduct from reoccurring. IPPSA/SPPA noted section 91(1) of the PUB Act, which provides that no owner of a public utility, shall:

> 91(1)
>
> ...
>
> (c) adopt, maintain or enforce a regulation, practice or measurement that is unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory or otherwise in contravention of law, or provide or maintain a service that is unsafe, improper or inadequate, or withhold or refuse a service that can reasonably be demanded and furnished when ordered by the Board,
>
> (d) make or give, directly or indirectly, an undue or unreasonable preference or advantage to any person or corporation or to any locality or to any particular description of traffic in any respect whatsoever, or subject a particular person or corporation or locality or particular description of traffic to any prejudice or disadvantage in any respect whatsoever,
>
> ...

Further, IPPSA/SPPA stated that sections 28 and 29 of the PUB Act give the Board the requisite jurisdiction to effect any remedy it views appropriate. IPPSA/SPPA submitted that there is evidence that demonstrates that the conduct of TransAlta and EPGI is inconsistent with and in contravention of the EU Act and the PUB Act. The proposed tariffs should not be approved unless and until the Board remedies the offensive conduct.

IPPSA/SPPA noted the different approaches that TransAlta and EPCOR have taken with respect to corporate organization. EPCOR has separated its business units into stand-alone entities whereas TransAlta has not. IPPSA/SPPA noted that TransAlta uses the same employees for regulated and unregulated activity although the employees account for their time when working on non-regulatory matters. IPPSA/SPPA suggested that TransAlta has failed to give effect to the functionalization of business units required by the EU Act.

Position of the FIRM Customers

The FIRM Customers noted its concerns with the changes that arose in the corporate structures of regulated electric utilities as a result of electric restructuring. The FIRM Customers noted that the Utilities traditionally operated as integrated entities with all parts of their regulated business under one corporate entity. In this manner, regulatory oversight provided checks and balances for each functional area of the company. The FIRM Customers stated that intervenors could monitor affiliate transactions and requested that the regulator act to prevent abuses of these relationships. The FIRM Customers also submitted that it was simpler to monitor the dealings of one integrated entity dealing with a number of affiliates than a number of functional components dealing with each other and various unregulated affiliates.

The FIRM Customers submitted that, with the 1998 changes to the EU Act, it became obvious that the integrated GENCO/TRANSCO/DISCO single corporate structure of the existing Utilities did not lend itself to the realities of the new world. The FIRM Customers noted that there are now many situations in which the separate functions of the old integrated Utilities will find themselves at odds with other functions of the same corporation. The FIRM Customers argued that this complicates regulatory oversight, particularly when affiliate transactions are added to the mix.

The FIRM Customers submitted that this situation requires change so that the corporate structure and governance are properly instituted to give effect to the promises of deregulation and to allow the oft-mentioned advantages of deregulation to customers to flourish.

Board Findings

The Board shares the general concerns stated by Intervenors with respect to the changing nature of the relationships between the entities of the former integrated Utilities and their non-regulated affiliates. The Board acknowledges that there are more complications involved in regulating the relationships between affiliates in the restructured environment.

The Board would like to stress that an important step in alleviating parties concerns with the relationships between regulated and non-regulated entities is to provide sufficient transparency in their dealings.

The perception of the nature of the relationships between regulated and non-regulated entities becomes as important as the actual nature of their dealings. For this reason, the greater the transparency in the relationships between affiliates, whether or not they are regulated, the more

likely that the relationships will be acceptable to the Board and interested parties. Taking into account these comments, the Board will deal with the specific recommendations on these relationships in the following sections.

(1) Code of Conduct

Several parties stressed the need for a code of conduct to deal with the relationship between the regulated Utilities and their non-regulated affiliates. There are ongoing processes before the DRD that are dealing with an Affiliate Relationship Code of Conduct (Code of Conduct) and a draft regulation for Roles, Relationships and Responsibilities of Wire Owners, Wire Service Providers and Retailers. The DRD has undertaken a consultative process with concerned parties to resolve the issue of developing a Code of Conduct and to determine an appropriate regulation on Roles and Relationships. It is intended that the Code of Conduct will set out specific rules for behaviour and will be enforced by the appropriate provincial authorities.

Position of EAL

EAL addressed the need for a code of conduct to prevent a potential market imbalance between integrated Utilities and other participants in the electric industry as a result of information sharing between the DISCO, GENCO and TFO functions. EAL noted that some of its concerns have been addressed by the DRD Guidelines, Exhibit 180. Specifically, the Guidelines contemplate:

- A level playing field for new and existing TFOs, including timely access to public data on the existing transmission system and to information on opportunities to provide transmission facilities.
- DISCOs and TFOs are required to provide the TA with timely notice and with information pertaining to potential requirements for their system.

EAL stated that the DRD Guidelines do not address a couple of areas of concern that they have. EAL considered that the integrated Utilities currently have an advantage over potential competitors for provision of new generation, system support services and transmission facilities. This advantage is largely the result of access to information not available to competitors. EAL suggested that there is an incentive for the DISCO to advise its affiliated wire owner of new transmission requirements well in advance but not to approach the TA until the affiliate has developed a solution and is in a position to present the TA with a virtual *fait accompli*. EAL suggested that another area of competitive advantage existed for the affiliated GENCO. Independent power producers planning new generation or co-generation must arrange for backup power from the DISCOs. If the DISCO passes this information along to the affiliated GENCO, a competitive advantage would be created for the GENCO relative to the independent power producer or other potential competitors of that project.

EAL submitted that flow of information with respect to potential transmission or generation opportunities among the functional units of the regulated utility or between the regulated utility

and its unregulated affiliates must be eliminated if the flow of information creates impediments to competition. In order to prevent the impediments to competition, the information must flow to the TA but it also must not flow between or among the DISCO, TFO, GENCO or unregulated affiliate. EAL recommended that a strict Code of Conduct must be imposed on the regulated Utilities in order to prevent the abuse of information between entities. EAL did not recommend that the code of conduct be imposed on the TFOs as part of the Terms and Conditions. EAL recommended that there should be substantial financial penalties for both the corporation and for individuals who breach the code of conduct.

Position of IPPSA/SPPA

IPPSA/SPPA questioned the appropriateness of Edmonton Power Distribution Inc. (EPDI) having customer load data that is not available to competitors who may wish to provide services to these customers. Although the DRD intends to address, in its Code of Conduct initiative, competitive advantages that arise between business units, there is a problem with these business arrangements today. IPPSA/SPPA stated that there is commercially valuable information in the hands of the EPCOR group of business units, which the companies have taken advantage of.

IPPSA/SPPA submitted that there is evidence that EPDI is capturing customers now, with the intent to lock them up beyond 2001, or well into the era of deregulation. IPPSA/SPPA further submitted that the EPCOR companies also refuse to disclose customer information and load data that gives them a significant competitive advantage. IPPSA/SPPA stated that the time for corporate reorganization to give effect to the practical functionalization mandated in the EU Act is now, as is the time for an effective and enforceable code of conduct to be in place. It is now that EPDI is capturing market share well beyond 2001, the time set forth in the EU Act for the open, fair, and competitive market, which allows for customer choice and for multiple buyers and sellers at the retail and wholesale level. IPPSA/SPPA questioned the chances of competition succeeding if the best of the customer crop is picked off before 2001. IPPSA/SPPA recommended that a code of conduct be implemented now.

Position of EPGI/EPTI

EPGI noted that the DRD currently has a process under way to address affiliate Code of Conduct issues. This process is expected to be completed this fall and EPGI stated that there is no reason to anticipate that this process will not be successful and effective in addressing the substantive issues. EPGI submitted that the process is a sound one and disagreed with any attempt by IPPSA/SPPA to usurp the process.

Additionally, Dr. Lewin provided the commitment of EPGI to voluntarily develop and implement an appropriate code of conduct in concert with the DRD Code of Conduct process. However, EPGI noted that neither EPDI nor Edmonton Power Customer Services Inc. (EPCI) were part of this proceeding and therefore it would be inappropriate to accept IPPSA/SPPA's suggestion.

Board Findings

The Board notes that there is a process initiated by the DRD that has run partly in tandem with this proceeding and which is dealing with setting a Code of Conduct. Given that this process is in progress, the Board considers that it would be counter-productive to make any determinations in this proceeding with respect to a code of conduct for the Utilities.

The Board agrees with parties concerns that a code of conduct is necessary to address both the presence of bias and the apprehension of bias between affiliated entities. The extent to which restrictions on the affiliates are necessary, will be determined through the DRD process. The Board is satisfied that parties have had the ability to express their concerns in the process undertaken by the DRD. The Board is hopeful that the processes currently in progress before the DRD will resolve the issues raised by parties concerning a Code of Conduct and the Roles and Relationships between entities. Assuming the process is successful, the Board may then be responsible for enforcing some of the conditions of the Code of Conduct.

(2) EPGI/EPTI

EPCOR has approved the restructuring of its business units into separate stand-alone corporate entities with separate and distinct assets, liabilities, and capital structures. Two of EPCOR's subsidiaries are applicants in this proceeding – EPGI and EPTI. EPDI and EPCI are not parties to these Applications and are not currently regulated by the Board.

Position of the FIRM Customers

The FIRM Customers noted that the EPCOR group has created separate companies to conduct the functional areas of the companies' business, however, the problem arises when the corporate governance of the companies is examined. Each of the EPCOR companies has the same Board of Directors. The FIRM Customers submitted that to achieve a competitive market, the participants would have to have different Boards of Directors. The FIRM Customers recommended that the creation of a separate and distinct Board of Directors for each individual company should be required in order to insure proper governance.

The FIRM Customers further noted that, with the relatively recent corporate restructuring within the EPCOR group, the applicants in this proceeding do not own the rate base for which they have applied for a return, but rather the parent company is the owner of the operating assets of the companies. The FIRM Customers also stated its concern that, at the time of the hearing, there was not an agreement in place by which the regulated companies leased or otherwise used the assets of the parent company. The FIRM Customers therefore recommended that EPGI and EPTI be directed to file such agreements. EPGI and EPTI should also be required to file valuations of the same assets and property and articulate their positions on how these should be rate based, given that they are owned by an entity that is not an applicant in this proceeding.

Position of IPPSA/SPPA

IPPSA/SPPA stated that, although EPCOR has separated into legal structures, it has not achieved separate working structures that operate independently at arms length. IPPSA/SPPA noted EPGI/EPTI's agreement that it was appropriate to adopt the functionalization of EPI into EPGI, EPTI and Customer Service Inc. now rather than to wait for 2001 when generation will no longer be regulated. IPPSA/SPPA suggested that the restructuring has not gone far enough. All of the EPCOR business units (EPGI, EPTI, EPDI and EPCOR Power Development Corp.) share common directors and some common officers. IPPSA/SPPA noted that EPCI is not currently operative and is viewed internally as distribution. Further, the relationships between the remaining business units are non-arms length. For example, there are no power supply contracts between the business units, nor are there lease agreements between EPCOR and EPTI and EPGI relating to the use of assets owned by EPCOR.

Additionally, EPCOR Power Development Corporation operates as the unregulated affiliate of EPGI but does not exist as a separate entity with its own employees and generation planning department. IPPSA/SPPA noted that EPCOR Power Development Corporation has three projects in development, two of which are significant in size and capital cost, and that there has been assistance provided to the group from EPGI.

Position of EPGI

EPGI noted IPPSA/SPPA's arguments, relating to TransAlta, that all payments to non-regulated energy marketing affiliates should be disallowed. EPGI stated that it was unclear whether or not IPPSA/SPPA intended that this submission should apply to EPGI. EPGI submitted that there is no basis for IPPSA/SPPA's assertion as it may relate to EPGI. Payments made by EPGI to Encore Energy Solutions LP (ENCORE) are for energy management services provided by ENCORE to EPGI. ENCORE does not own any centralized trading that has been paid for by EPGI.

EPGI noted the FIRM Customers' submission that separate Boards of Directors be created for each EPCOR subsidiary. EPGI submitted that it is not the Board's role to involve itself in matters of internal corporate governance and that the Board does not have jurisdiction over most of EPCOR's subsidiaries. EPGI suggested that the FIRM Customers proposal resembled forced divestiture, which is not endorsed by the EU Act. EPGI had significant jurisdictional concerns with the FIRM Customers' recommendation. Further, EPGI noted that this matter should be addressed by the DRD process on affiliate code of conduct issues.

Board Findings

EPCOR has chosen to separate its functional entities into separate legal entities at this time. Both the FIRM Customers and IPPSA/SPPA have recommended that EPCOR should go further in this separation by also having distinct Boards of Directors. The Board generally agrees with EPGI that it is not the Board's normal practice to involve itself in particular matters of corporate governance. The Board however observes that the perception of the dealings between the entities

of EPCOR would likely be improved if EPCOR maintained distinct Boards of Directors for each of its entities. The Board considers that it is more appropriate to restrict itself to the impact that the corporate structure has on providing generation and transmission service, in the case of EPGI and EPTI. The Board also considers that when the Affiliate Code of Conduct Regulation is finalized there may be guidance provided which affects corporate structures.

To the extent that the corporate structure affects transfers between regulated and non-regulated affiliates, the Board considers that it is part of its mandate to assess the reasonableness of these transactions. Therefore the Board agrees with FIRM that the agreements that allow EPGI and EPTI to use EPCOR assets and property and the valuations of these same properties can and should be reviewed by the Board. Therefore, the Board directs EPGI, if a future GTA is required, and EPTI, at the next GTA, to provide valuations of assets and properties that have been transferred between entities and agreements that support such transfers.

The Board is concerned that any transactions between affiliates be compensated for at fair market prices. In order to ensure that these transactions are following fair market prices, the Board directs EPTI to keep track of and report on, in future GTAs, the amount of manpower used by non-regulated entities from EPTI. The report should include the number of hours, the rate at which labour is charged out and how the charge rate was determined. A breakdown should be included for work done for non-regulated affiliates in Alberta and those that are outside of Alberta, if any. The Board considers that this will aid in providing an appropriate level of transparency in the relationships between EPTI and its non-regulated affiliates.

The Board wishes to further understand the relationships between amounts that are charged to or received from the unregulated affiliates of the regulated affiliates. Accordingly, in future GTAs, the Board directs EPTI to provide the following information on contracts or services that result in amounts being charged to the regulated utility by unregulated affiliates or that the regulated utility charges to unregulated affiliates:

- A list of services provided or received.
- The annual amount associated with those services.
- The contract or service agreement supporting those charges.
- How the rate or charge was determined and how does it relate to a market assessment of the reasonability of those charges.

(3) TransAlta

TransAlta has not created separate legal entities for its business units for the test period. Some parties questioned the appropriateness of TransAlta maintaining itself as an integrated company at this time. It has also been suggested that TransAlta has a competitive advantage by virtue of the relationship between its regulated and non-regulated activities. Also at issue is the question of how costs are allocated between its regulated and non-regulated activities.

Position of the FIRM Customers

The FIRM Customers noted that TransAlta continues to operate as one integrated corporate entity. The FIRM Customers stated its concern with this continued practice by TransAlta. The FIRM Customers noted that the different segments of TransAlta's business are managed separately and this leads to conflicting goals between the segments. The same company and hence Board of Directors covers competing portions of old regulated entities. The FIRM Customers submitted that TransAlta be directed to file and act on a planned corporate and Board of Director restructuring to insure proper corporate governance and checks and balances are in place.

Position of IPPSA/SPPA

IPPSA/SPPA stated that TransAlta controls the majority of generation, has the majority of loose juice which it markets for its own account and has the ability to influence pool price through its bidding practices and preferential market knowledge. Therefore IPPSA/SPPA submitted that the dominant market power currently held by TransAlta should be mitigated. IPPSA/SPPA suggested that TransAlta has resisted the changes mandated by the EU Act until the last possible moment in order to capture and retain as large a piece of the market as possible.

IPPSA/SPPA noted that TransAlta assigns its employees to both regulated and unregulated activities. IPPSA/SPPA was concerned that TransAlta employees can provide information to the unregulated affiliates. IPPSA/SPPA emphasized that what the unregulated affiliates do and how they interact with TransAlta is a key concern in the restructuring.

IPPSA/SPPA suggested that the most important of all the activities which are capable of yielding a competitive advantage and a preference to TransAlta and its affiliates relate to bids of energy into the pool and offers to purchase energy from the pool. In a competitive market, if one party knows the price at which the majority of a commodity will be offered for sale, and the same party knows the price one of the largest buyers is willing to pay, a competitive advantage is held as compared to other market participants who do not have this information. IPPSA/SPPA suggested that TransAlta's affiliate, TransAlta Energy Corp and its wholly owned subsidiary TransAlta Energy Marketing Corp are in this position. Not only does the same TransAlta affiliate bid the TransAlta GENCO's energy into the pool, it is responsible for procuring and bidding imported power into the pool. This includes electricity that is purchased in the Pacific Northwest and wholesaled into Alberta. To the extent TransAlta Corp. has any merchant plant power to sell, TransAlta Energy would also look after that. Not only do these non-regulated affiliates transact bid and offers into the pool, procure and bid import energy into the pool, they manage the net position (effectively hedge the pool price risk) for both the TransAlta GENCO and DISCO. IPPSA/SPPA stated that the apparent charge made by TransAlta Energy for the risk management of TransAlta's net position was \$0.6 million for the DISCO function. The charge in respect of the GENCO side was \$1.7 million. IPPSA/SPPA noted that these risk management activities are provided pursuant to a general arrangement and not to a contract. IPPSA/SPPA stated that TransAlta's DISCO has not sought competitive bids for the provision of risk management services in a fair and competitive process. This is required pursuant to section 52(2) of the EU

Act before these costs can be included in revenue requirement. IPPSA/SPPA argued that, not only must a competitive process be carried out, but also the result of that process must be an arrangement, which is prudently made. Therefore, IPPSA/SPPA recommended that, as TransAlta has failed to meet the requirement of this section, these costs should be disallowed.

IPPSA/SPPA noted TransAlta's comment that its contract with TransAlta Energy Management provides a cost saving to customers. IPPSA/SPPA reiterated its concerns that TransAlta's dealings with TransAlta Energy Marketing were an obstruction to the goal of creating an open, fair and truly competitive power pool. IPPSA/SPPA noted its concern that TransAlta viewed this in terms of cost savings rather than to acknowledge the concern over market power. Further, in response to TransAlta, IPPSA /SPPA submitted that the market surveillance provisions in the EU Act do not preclude the matters at issue from being dealt with by the Board or in any other forum having jurisdiction. IPPSA/SPPA suggested that this proceeding is the most appropriate forum and is the one best positioned to provide effective, timely and meaningful relief. IPPSA/SPPA commented that a remedy after 2001 is no remedy at all.

IPPSA/SPPA suggested that another area where TransAlta has a competitive advantage is in market penetration and customer access and information. TransAlta's account managers also sell non-regulated products. IPPSA/SPPA did not accept that a TransAlta sales representative would advise its customers to go to a third party supplier. IPPSA/SPPA submitted that the Energy Procurement Report, entered as Exhibit 108, did not support TransAlta's contention that its staff separated their presentations on behalf of the regulated versus the unregulated company. The Energy Procurement Report is a sample report produced by TransAlta Energy Marketing to a customer. IPPSA/SPPA suggested that the Energy Procurement Report does not make a distinction between TransAlta Utilities and TransAlta Marketing. Also, the Energy Procurement Report is written in such a way as to represent to the customer that TransAlta will be providing it with an analysis of its load data without any suggestion that the load data must be 'released" by TransAlta to TransAlta Energy Marketing. Nor is there a request for a written release of customer information. However, it is TransAlta's customary practice to obtain a written release whenever a customer requests load data be supplied to a third party. IPPSA/SPPA submitted that this is a difference in treatment between TransAlta Energy and third parties and constitutes preferential treatment by TransAlta to its affiliate.

IPPSA/SPPA submitted that these activities make it clear beyond the balance of probability that TransAlta is providing TransAlta Energy with customer specific load information in the ordinary course of its business, without specific approval and for the express purpose of furthering TransAlta's and TransAlta Corp.'s commercial interest. IPPSA/SPPA stated that it is this type of relationship which creates a competitive advantage. IPPSA/SPPA submitted that this conduct must be addressed and recommended that TransAlta and its TransAlta Energy Marketing affiliate should separate all dual duty activity. Physical separation of the two is desirable if not necessary, as is a strict and transparent code of conduct that can be enforced. IPPSA/SPPA stressed that, given the urgency to level the playing field prior to retail competition, a directive to have the Code of Conduct implemented by the next filing to the Board is not adequate. IPPSA/SPPA

submitted that a binding implementation plan be filed with the Board within one month of the Board's Decision or at the time of the re-filing, whichever is sooner. IPPSA/SPPA recommended that approval of the present Application should be conditioned on terms that require TransAlta to legally and physically separate all regulated and non-regulated marketing activity and personnel.

Position of TransAlta

TransAlta noted the concern of Intervenors that there is the potential for TransAlta personnel to act for both TransAlta's regulated and non-regulated entities at the same time. TransAlta noted that, when its staff is going to discuss a non-regulated offer with a customer, they ensure that the customer is aware that it is from a distinct entity from the regulated business and that there are competitors in the area.[16] TransAlta stated that it has a corporate policy on the matter and offered to investigate any concerns that Intervenors might like to pursue in appropriate forums.

TransAlta also reaffirmed its commitment that there should be no cross-subsidization between its regulated and non-regulated entities. TransAlta stated that the level of payments that it made under its contract with TransAlta Energy Marketing was consistent with prior years. TransAlta forecast to pay \$2.3 million in each of 1999 and 2000 to TransAlta Energy Marketing. This was split as \$1.7 million to GENCO and \$0.6 million to DISCO. TransAlta stated that this was a cost saving to the customer compared to doing the same work in-house. In comparison, EPGI was spending \$2.3 million in equivalent expense which TransAlta stated was in the same range although TransAlta has a larger GENCO function. TransAlta submitted that the \$2.3 million contract for services with TransAlta Energy Marketing is cost-effective.

Regarding rates charged to non-regulated affiliates for work done by employees of the regulated company, TransAlta stated that, whenever possible, expenses are incurred directly by the non-regulated entity. When personnel from a regulated business unit are seconded to work for a non-regulated entity, a fully-loaded rate is charged for their services. TransAlta stated that there is minimal non-regulatory work done by utility personnel.
In response to IPPSA/SPPA, TransAlta stated that it has not violated either the EU Act or the PUB Act. TransAlta submitted that no evidence was presented to demonstrate an abuse of market power. TransAlta noted the comment from IPCAA that IPCAA had not filed a complaint regarding an abuse of market power. The Market Surveillance Regulation AR 278/98 is designed to provide protection against abuses of market power and there have been no complaints against TransAlta filed under it. TransAlta submitted that the allegations of abuse of market power made by IPPSA/SPPA should be rejected.

TransAlta noted that the EU Act clearly does not require any party to transfer or divest itself of any property owned by it (section 3(1)). Nothing in the EU Act requires TransAlta to establish separate corporations for the Generation, Transmission and Distribution functions nor is it required of TransAlta that the Transmission and Distribution functions be separated. Further, nothing in the EU Act prevents TransAlta from building, either directly or through an affiliate,

[16] Tr. p.3178

new unregulated generation in the province, nor is it prevented from having its unregulated affiliates engage in marketing activities in Alberta. TransAlta suggested that if anyone disagrees with this it needs to be addressed to the DRD and not to the Board.

With respect to the Code of Conduct, TransAlta noted the precaution taken by it to ensure that there is no abuse of its position as a significant supplier of electricity in Alberta. TransAlta noted that there is a process currently underway through the DRD to develop a new Code of Conduct and the recommendation that TransAlta be forced to adopt a new one is misdirected. TransAlta submitted that there is no evidence in this proceeding to indicate that TransAlta has in any way violated either the EU Act or the PUB Act.

TransAlta noted the request of IPPSA/SPPA that the $2.3 million payment from TransAlta to TransAlta Energy Marketing be disallowed. TransAlta noted that only a portion of the $2.3 million charge related to the risk management services noted by IPPSA/SPPA. TransAlta also disagreed with IPPSA/SPPA that TransAlta's activities in relation to its affiliate violate section 52(2) of the EU Act. The $2.3 million paid by TransAlta to TransAlta Energy Marketing represents payment for a significant amount of work for both the GENCO and the DISCO and not just for risk management services. It was estimated that only 25% of that charge relates to risk management. TransAlta noted that it is able to reduce its costs by having TransAlta Energy Marketing manage small power accounts, perform risk management plus the pool modeling, and all of the day-to-day activities associated with getting the offers into the Power Pool.

TransAlta noted that section 52(2) of the EU Act deals with "the costs associated with financial arrangements to manage financial risk associated with the pool price." TransAlta stated that this section pertains to the actual purchase of some additional commodity by a DISCO, particularly with longer-term contracts. TransAlta did not agree with IPPSA/SPPA that this section applies to the risk management services provided by TransAlta Energy Marketing. Further, even if IPPSA/SPPA's interpretation of the section is correct, TransAlta has not included any costs associated with hedging the commodity in its Application and TransAlta's actions do not violate section 52(2) of the EU Act. TransAlta reiterated that only staff-related costs associated with the risk management services have been included in the Application. Therefore, TransAlta recommended that the request of IPPSA/SPPA to disallow the $2.3 million payment to TransAlta Energy Marketing should be ignored.

TransAlta referred to IPPSA/SPPA's allegations that TransAlta is providing TransAlta Energy Marketing with customer specific load information in the ordinary course of its business without customer approval. TransAlta submitted that these allegations are groundless and that there is no evidence of preferential treatment being afforded TransAlta Energy Marketing, nor is there any evidence of customer specific load information being supplied without customer approval. TransAlta stated that the release of information to TransAlta Energy Marketing is done in the same manner as for any third party. TransAlta referred to Exhibit 108 (sample procurement report from TransAlta Energy Marketing) as verification that a proposal from TransAlta Energy Marketing would not proceed absent customer agreement. TransAlta also noted that there is no

cost discrimination against a non-affiliated marketer when a request for load data is made. TransAlta stated that the utility collects more revenue from TransAlta's non-regulated entity than from another non-regulated entity due to TransAlta charging labour to TransAlta Energy Marketing.

In response to comments from IPPSA/SPPA regarding generator market power in Alberta, TransAlta stated that there was no evidence that TransAlta has conducted its bidding of hydro generation in an inappropriate manner and any such allegation should be disregarded. TransAlta also disagreed with IPPSA/SPPA's contention that, absent deferral accounts, a GENCO with loose juice will have an incentive to withhold supply during periods of tight supply. TransAlta noted the evidence of Mr. Way that it has consistently made the choice of maximizing the output of its generating units, even if such a decision negatively impacts TransAlta from a financial point of view.[17]

Board Findings

It is not the Board's normal practice to involve itself in particular matters of corporate governance. Therefore the Board does not agree with the submission by the FIRM Customers that TransAlta be directed to file and act on a planned corporate and Board of Directors restructuring. The Board considers that it is more appropriate to restrict itself, at this time, to the impact that the corporate structure has on providing generation, transmission and distribution service. However, the Board observes that the perception of the relationships between the separate functions would likely be improved if TransAlta were to arrange its functions into separate legal entities with distinct Boards of Directors.

The Board notes that legislation has set out the requirements for the Utilities in the restructuring process. There is no requirement for legal separation of the functions nor is there a requirement for divestiture. The Board also considers that when the Affiliate Code of Conduct Regulation is finalized there may be guidance provided which affects corporate structures. The Board however will not attempt to anticipate such changes.

The Board is concerned that any transactions between affiliates be compensated for at fair market prices. In order to ensure that these transactions are following fair market prices, the Board directs TransAlta to keep track of and report on, in future GTAs, the amount of manpower used by non-regulated entities from the regulated TransAlta affiliates. The report should include the number of hours, the rate at which labour is charged out and how the charge rate was determined. A breakdown should be included for work done for non-regulated affiliates in Alberta and those that are outside of Alberta. The Board considers that this will aid in providing an appropriate level of transparency in the relationships between TransAlta and its non-regulated affiliates. The Board accepts that the transactions forecast between TransAlta and TransAlta Energy Marketing for the test years have been concluded at a fair value.

[17] Tr. p.2353-2354

2. RESTRUCTURING ISSUES

(c) Relationship Between Regulated and Unregulated Activities

IPPSA/SPPA has made several suggestions that it is the Board's responsibility to ensure a level playing field between the regulated Utilities, specifically TransAlta, and their competitors. The Board does not consider that it is within its mandate to assume responsibility for this broad role. The Board notes that the position of Market Surveillance Administrator has been created and has been given the power to address issues dealing with market power. Sections 9.1 and 9.2 of the EU Act set out the provision for the creation of the Market Surveillance Administrator and describe the surveillance duties for which the Market Surveillance Administrator is responsible. The Board deals with aspects of market power only as it directly affects the rates and/or the costs that the Board approves and to ensure that there is no cross-subsidization of non-regulated operations by the regulated entity. For example, should the Board find that a regulated entity has taken advantage of a position of market power to acquire a higher payment from customers than it would otherwise be able to, then it is in the Board's jurisdiction to adjust the quantum of the payment. The Board considers that sections 91(1)(c) and (d) of the PUB Act as referenced by IPPSA/SPPA support this. However, this is distinct from the suggestion by IPPSA/SPPA that the Board has the responsibility to ensure that a regulated utility is not in a position to exercise market power.

The Board wishes to further understand the relationships between amounts that are charged to or received from the unregulated affiliates of the regulated affiliates. Accordingly, in future GTAs, the Board directs TransAlta to provide the following information on contracts or services that result in amounts being charged to the regulated utility by unregulated affiliates or that the regulated utility charges to unregulated affiliates:

- A list of services provided or received.
- The annual amount associated with those services.
- The contract or service agreement supporting those charges.
- How the rate or charge was determined and how does it relate to a market assessment of the reasonability of those charges.

3. GENCO/TRANSCO/DISCO

(a) Generation

(1) Modeling of Generation Forecast

(A) Accuracy of Modeling

The ability of models to develop a fair and reasonable generation forecast for the test years 1999 and 2000 was called into question in these proceedings. Most of the concern related to the difficulty in forecasting pool prices and surplus/shortfall given the sensitivity of input parameters when the system is tight.

Position of AE

Mr. Beckett summarized AE's views as follows:

> I think most participants should agree that the volatility around the expected result would be extremely high, very, very sensitive to all of the different input assumptions that you are making. So you have to ask yourself the question, Why have I gone to this effort to get this single line forecast when the result of it is that I create huge business uncertainty for myself on the DISCO end and the GENCO end around the pool price volatility, and that quickly took us to the discussion of deferral accounts.[18]

Position of EPGI

Dr. Lewin summarized EPGI's position as follows:

> When we are talking about the forecast, I want it to be clear that the models that we have used have been well tested, that they have been back cast with actual numbers. So the models themselves are accurate....On a go-forward basis, and when we are talking about forecast accuracy, if you like, what we are really talking about is the inputs into the model, the assumptions that have been made, and they are not all assumptions, but some are facts, of course, but it is really discussion around the actual input assumptions that we are really talking about. So it is not a question of being dependent upon who uses the models. The models are okay. It is really a question of what comfort you have with respect to the assumptions that you are inputting into that model. Really, that is where the debate should lie, and we use the best information available to us; et cetera, to input into that model.[19]

Dr. Bridgeman noted the following with respect to the forecast accuracy of the models:

[18] Tr. p.4687-4688
[19] Tr. p.687-688

> The task here is to come up with an annual forecast, and we believe that over the course of a year, some months will be up, and some months will be down, but we believe that this is a reasonable forecast of what we can be expected to do in 1999 and 2000.
>
> ...Again, there are a lot of things in these models, and we believe that these models can be, if we discover errors, they can be corrected, and we can come up with a reasonable forecast.

Position of TransAlta

Mr. Way summarized TransAlta's position as follows:

> The different seeds do create some scatter, and that is, I guess, the reason for running a number of runs, and that is, I would say, just a normal part of the modeling exercise. It is not to discount that there are some runs that are, I will say, out a distance on a bell curve from the average. On the other hand, using the model and running several seeds, I think we are confident enough that we get a pretty good idea of what the price is likely to be, with some uncertainty around it, no doubt....So I'm the first to acknowledge that there is some significant volatility with electricity prices and that the units do perform well and then perform poorly, and prices do go up and down in those periods.[20]

Position of IPCAA

Mr. Drazen summarized IPCAA's position as follows:

> For 1999, the three utilities cannot agree on a number among themselves, even using the same assumptions about loads and resources. Some of the assumptions and modeling methods are crude and even incorrect, such as the so-called 105 megawatt TransAlta Energy Management plant addition at Sundance for July 1999, and when the assumptions are changed, the forecast changes by several dollars per megawatt hour....When we got to this case, we said, What's really the purpose of the forecast? The purpose of the forecast isn't to make the modeler rich; although we might like that. It is I think first and foremost to come up with a number on the surplus/shortfall to feed into the reservation price. It is the dollars. The customers really don't care what the generation output is. They care what the dollars are. They care what the pool price is, and they care what the reservation prices are. The question is, How well can we determine that? If we look just at the three utilities for the evidence that was submitted here, the utilities themselves using common assumptions couldn't agree on a number. TAU had a number of $30 million of surplus for itself. EPGI I think estimated 60 million for TAU. So how do you deal with that? The answer is recognize what the models can do and

[20] Tr. p.3764-3765

> can't do, and recognizing all the things that the models can't do and that purpose is to come up with the dollars, set a base line on the dollars and then have a deferral account to account for differences from that. That seems to us be the most logical, the simplest, and the most effective way of dealing with the real question of what is the surplus/shortfall amount.[21]

Board Findings

The Board agrees that the tightness of the system may result in a volatile pool price during the test years, making it difficult to determine accurate surplus/shortfall amounts by unit and by GENCO. The Board notes that the determination of an accurate surplus/shortfall amount depends on the hourly level of generating unit output and the corresponding hourly pool price. Further, the Board recognizes that it is more difficult, in a tighter supply-demand situation, to model and predict the effect of hydro generation given the many factors that affect the operation of hydro generating capacity and the choices of when to use hydro capacity.

Notwithstanding the above, the Board considers that with suitable input parameters and appropriate modeling techniques, it is possible to determine a reasonable baseline forecast of the annual surplus/shortfall dollars by generating unit and GENCO for the purposes of fixing reservation prices for the test years. The Board also considers that there is benefit to be gained by going through the exercise of arriving at a baseline forecast that is as reasonable as possible.

Accordingly, the Board will proceed to make determinations respecting input parameters to be used for the re-run of the models and the modeling techniques (type of model, iterations, etc.) to be followed.

The Board, in later sections in this Decision, will make a determination respecting the models to be used and whether or not Deferral accounts need be instituted during the test years.

(B) Simulation of Actuals

EPGI used PROSYM to simulate 1998 actuals in order to demonstrate that the production and pool price simulations are sufficiently consistent with the actuals. EPGI concluded that PROSYM constituted a reliable and unbiased forecasting tool since the simulated values closely resemble the actuals for 1998. However, EPGI had "frozen" several inputs and modified several assumptions during the course of the testing.

Position of EPGI

EPGI maintained that the PROSYM simulation of the actuals is proof of the model's ability to produce reasonable forecasts of the 1999 and 2000 pool prices. EPGI further stated that they have learned from the exercise and, as a result, they were able to improve some of the input

[21] Tr. p.4312-4336

assumptions and improve modeling of certain generation characteristics such as Maintenance Outages.

EPGI repeated the analysis many times to investigate the impacts of varying input assumptions and to observe improvements that the better assumptions made. EPGI emphasized that all changes made are improvements resulting from learning how to better model some of the inputs rather than an attempt to keep changing assumptions until desired results are obtained.

Position of TransAlta

In FIRM.TAU-17, TransAlta was requested to provide all analyses performed comparing the results of the ENPRO model to actual historical data. TransAlta responded with a schedule and graph comparing an ENPRO backcast of 1997 versus actual 1997 pool prices. TransAlta explained that it was a relatively simplistic backcast utilizing:

- average monthly Mid-C prices as a proxy for import bids,
- TransAlta's actual generation maintenance schedules (actual forced outages not modeled),
- average actual monthly gas prices used to proxy gas unit bids and
- actual hourly demand

TransAlta also provided a comparison of hourly average hydro production for 1997 actual and 1999 ENPRO forecast. The purpose of this comparison was to demonstrate that ENPRO:

> …does replicate the shaping that we can normally do with hydro quite well, given 1997 is the year we are truing up to.[22]

Mr. Way commented on backcasting as follows:

> One of the difficulties I think we have got here is that Edmonton tried to true up to 1998, which is, in our opinion, not a typical hydro year for the reasons we were saying before. It was a wet year, plus the wetness occurred in high-price periods, so it was not a very typical year to true up to. We have been unable to, I guess, in detail see how they did true up the hydro. It was one of the things we had to pay particular attention to when we adopted ENPRO.[23]

Position of IPCAA

IPCAA questioned the practical value of the EPGI simulation of 1998 actuals. IPCAA's argument included two major points:

[22] Tr. p.3788
[23] Tr. p.3788

- That the 1998 simulation of the actuals does not prove that PROSYM is a reliable tool to forecast pool price and volumes in the years 1999 and 2000.
- That the input assumptions were frozen and/or adjusted deliberately to obtain results similar to 1998 actuals.

In respect to the first point IPCAA argued that:

> …the generation model could not be "reliable" by the EPGI standard because, by definition, it could not anticipate the better than forecast performance that the utilities promise that they could achieve.[24]

IPCAA also argued that if the PROSYM and ENPRO forecast were reliable, EPGI and TransAlta would not oppose deferral accounts.

In respect to the second point, IPCAA raised several examples where, in IPCAA's opinion, EPGI restricted the input assumptions to the 1998 actuals or adjusted the assumption so as to obtain results close to the actuals for1998. IPCAA included the following assertions:

- IPCAA argued that the 1998 simulation "forces" pool prices to match actuals for the majority of the hours because EPGI adjusted unit availability to match actual forced and planned outages. IPCAA concluded that only hydro resources remained to be dispatched by the model.
- IPCAA further argued that the scheduling of the planned outages was fixed to the actual time when the planned outage for each unit occurred in 1998.
- One of the major points raised by IPCAA is the treatment of imports in the simulation of actuals. IPCAA argued that import offers were based on actual pool prices and that this "forces" the simulations to produce pool price forecasts close to actuals.

Board Findings

The Board considers that the following two issues relate to the simulation of actuals:

- Whether the PROSYM model is capable of calculating the appropriate volumes given the "correct" input assumptions, and
- Whether the pool price can be forecast with sufficient accuracy to render deferral accounts unnecessary.

The Board agrees with EPGI that the simulation of 1998 actuals demonstrates that the PROSYM model is capable of producing reasonably accurate outputs given the appropriate choice of input assumptions. In other words, the Board agrees that the model can be "calibrated" to the actuals. In particular, the Board appreciates that the PROSYM model performs accurate scheduling of generation resources and models unit outages in a manner consistent with reality.

[24] IPCAA Reply Argument, p.6

3. GENCO/TRANSCO/DISCO
(a) Generation

The Board recognizes that "freezing" any input to the 1998 actual values reduces variability of the output volume and pool price forecasts and hence increases the likelihood that the model output will match the actuals. In particular, the Board recognizes that planned outages were input to match the actuals rather than letting the model schedule the outages using the internal optimization algorithms.

The Board, however, does not consider that EPGI's simulation of the 1998 actuals is a sufficient proof of PROSYM's capability to predict pool price in other years. EPGI has not completed a typical model testing that would comprise the following two steps:

- Calibrate the model to a calibration year (e.g. 1998). Fine tune input parameters and assumptions as appropriate.
- Perform simulation of other years on record without changing the fine tuned input parameters and other learnings from the calibration step. Original load profile forecasts, gas price forecast and unit performance forecasts have to be used in the analysis. The results have to be compared with the actuals including the distribution of pool prices and confidence intervals.

The Board notes that it may not be necessary to carry out any further generation modeling after 01 January 2001. However, if the need arises, the Board directs the Utilities to perform the above noted calibration either individually or as a joint effort at the time of the next GENCO GTA. The Board also directs the Utilities to prepare a distribution of the pool price forecast and confidence intervals of such a forecast as a means of calibrating to the actuals.

The Board, in the GENCO Deferral Accounts, Part 1-General, Section 3(a)(4) of this Decision, has found that forecast volumes can be modeled with sufficient accuracy to render a volume deferral account unnecessary. However, the Board found that it would be necessary to create a deferral account with respect to the models' forecast of hourly pool price.

(C) PROSYM vs. ENPRO

PROSYM and ENPRO are both production simulation models. Both models use Monte Carlo simulation as their basis to simulate generation performance. Both models are commercially available and both have been used by other electrical utilities and have a proven track record in various contested case proceedings.

Both models are complex in nature and have numerous input assumptions and settings that have to be specified by their operators. Furthermore, both models use proprietary algorithms, restricting detail of disclosed information by the utilities.

All three utilities stated that the models have similar underlying principles and that the major differences between the models include treatment of forced outages, hydro dispatch, imports, operating reserve and the number of iterations needed for the model to converge to expected

values. AE and EPGI used PROSYM while TransAlta used ENPRO in their filings. Only EPGI had both programs available to perform comparative simulations. AE did not have first hand experience with ENPRO and TransAlta did not have first hand experience with PROSYM .

Both models have the capability to represent unit forced outages and maintenance outages. Neither model can represent directly the availability of unit capacity above its MCR.

Both models have the direct capability to model operating reserve.

Neither of the two commercial models include a module to deal with settlement calculations. Consequently, Alberta's settlement model must be handled externally as a subsequent set of calculations. Settlement calculations require that interim results are output from the commercial model for each of seven sequential iterations used to represent the average production forecast.

The primary difference between the two models stems from their representation of hydro systems and from the inclusion of convergent Monte Carlo simulation techniques in PROSYM.

Position of AE

AE stated that one of the key differences between PROSYM and ENPRO is the treatment of hydro resources. AE also stated that in respect to hydro modeling, PROSYM's "perfect foresight" in dispatching available generation corresponded more realistically to the actual hydro dispatch.

AE acknowledged that there are some pluses and minuses to both hydro scheduling approaches but with respect to PROSYM, Mr. Beckett stated:

> That sounds very familiar to me, very similar to how a hydro scheduler would set his week up going into it, and the TransAlta hydro scheduler has very significant knowledge about the current and expected performance of the majority of the generating units in the province.[25]

While AE indicated that although they did not have the ENPRO program available, it was their understanding that PROSYM was more likely to dispatch hydro during high pool prices in the off peak hours. That behavior was, in AE's opinion more consistent with the way a human operator dispatches hydro resources.

AE was not aware of any unassailable differences between the results of the models that were due to the thermal modeling.

AE did raise the issue of convergent vs. non-convergent Monte Carlo simulation and that more iterations would be needed when using the ENPRO model.

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[25] Tr. p.4680

AE did not explicitly comment on the benefit of each model in respect to imports, operating reserve and forced outage treatment.

Position of EPGI

EPGI's position was that PROSYM was the better choice between the two models. EPGI had an advantageous position in respect to model comparison by having used both models.

EPGI stated that the primary difference between the models is their treatment of hydro. EPGI's position was that PROSYM's approach of optimizing available hydro energy over one week using knowledge of forced outages (perfect foresight) is better than ENPRO's approach where only guidelines are prepared for the energy to be dispatched on an hour by hour basis. EPGI's position may be best summarized from Mr. Bridgeman's rebuttal evidence:

> ENPRO is poor at optimizing hydro dispatch, and thus overstated the increase in the pool price when a generating unit was forced out. This weakness has been resolved for 1999 and 2000 with the use of PROSYM.

EPGI's position in respect to the number of iterations required to obtain statistically significant data is summarized in Mr. Bridgeman's rebuttal evidence as:

> In 1996, the utilities used an insufficient number of iterations for a regular Monte Carlo simulation.

EPGI stated that use of the convergent Monte Carlo simulation resolves this issue and seven iterations with convergent Monte Carlo are sufficient. Of the two models, only PROSYM has an option to use convergent Monte Carlo simulation. When commenting on the variability of the results, EPGI stated:

> This is to be expected given the significant differences in hydro dispatch between the ENPRO and PROSYM modelling software and the fact that TAU used a regular Monte Carlo simulation with only seven iterations. It is clear that the only relevant comparison that can be made respecting the pattern of pool prices is between EPGI's and APL's PROSYM runs.

Position of TransAlta

In their submission, TransAlta stated that:

> Although we have not compared the detailed workings of the two models, they appear to be essentially the same. Some differences are in the way that forced outages to units, hydro generation and operating reserve requirements are simulated."

3. GENCO/TRANSCO/DISCO
(a) Generation

TransAlta also acknowledged that the modeling of hydro is the primary difference between the two models.[26] While TransAlta acknowledged that they are not familiar with the PROSYM inner workings they believed that hydro modeling is similar with the exception of how much effective foresight each model has when scheduling hydro resources. With respect to the hydro scheduling, TransAlta was satisfied with their ENPRO simulations:

> We have calibrated the ENPRO model and the preprocessing that is done, and we have calibrated that, and we are very comfortable with how we have modeled the hydro and that it reflects historic performance. Given that, we believe that the modeling that has been prepared and presented by TransAlta here is reasonable and should be accepted.[27]

Furthermore, TransAlta was convinced that ENPRO modeling of hydro resources better reflects the actual actions of the hydro scheduler and therefore is superior to PROSYM. Consequently, TransAlta argued that the Board should accept ENPRO modeling of hydro resources.

TransAlta took issue with claims of EPGI and several intervenors that PROSYM results better reflect the actual hydro dispatch in the first few months of 1999 and in 1998. TransAlta argued that 1998 and the beginning of 1999 were abnormal years that could not have been forecast accurately.

Position of the Intervenors

IPCAA argued that both models are inadequate in forecasting the surplus/shortfall and pool prices. IPCAA did not indicate which model is better either overall or in respect to any particular modeling issue. However, indirectly IPCAA did offer some opinion on the accuracy of the two models:

> When you look at I think provided hourly data of actual hydro dispatch versus pool price, and I believe for the first nine months of the year, and when I plotted the data out, I couldn't find a single occurrence of having less than 400 megawatts of hydro when the price was $100 a megawatt hour higher. Their models scatter that region with dispatch in the runs. But in actual fact, there is clearly an incentive to put the pedal to the metal, if you will, when the price is getting really high.[28]

In their argument at page 38, IPPSA/SPPA presented a comparison of the actual hydro generation in the first three months of 1999 to the forecasts produced by the three utilities, and concluded that "the PROSYM model has done a superior job of estimating Hydro dispatch."

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[26] Tr. p.2166
[27] Tr. p.2166
[28] Tr. p.4435

The IPPSA/SPPA conclusion was based on their observation that AE's forecast more closely matched the actual hydro generation in the on-peak and off peak periods.

Board Findings

The Board considers the issue of the comparison between the ENPRO and PROSYM models is of primary importance in the context of the individual model's ability to provide accurate forecasts of the 1999/2000 surplus/shortfalls. In this respect, the Board considers the models to be similar in nature with two notable exceptions, namely:

- the scheduling of hydro resources, and
- the availability of convergent Monte Carlo simulation in the PROSYM model.

With respect to modeling the hydro resources, the Board takes note that PROSYM is more aggressive in its scheduling due to its "perfect foresight" of thermal unit forced outages while ENPRO is more conservative since, although it can be given some degree of flexibility to reschedule hydro in relation to thermal forced outages, it may "run out of water toward the end of month." The Board acknowledges that modeling within both models is a simplification of a complex decision process that takes place when a human scheduler utilizes all available information and his/her past experience to optimize water utilization.

The Board considers that given the complexity of the actual hydro scheduling, each model's hydro scheduling capability should be judged primarily by the model's ability to schedule hydro under both typical and atypical conditions. Hence, the model results are more important than the proximity of the internal algorithm to the actions of an actual human hydro scheduler.

The Board therefore concludes that the PROSYM hydro modeling appears to produce results that better match the actual observed results than does the ENPRO hydro model. The Board will provide its specific findings respecting hydro modeling in the Modeling Assumptions Part 1-General, Section 3(a)(E) of this Decision.

With respect to the use of convergent Monte Carlo simulation, the Board concurs with EPGI that the use of convergent Monte Carlo reduces the number of iterations required to obtain average results with narrow confidence intervals. However, EPGI does not offer any proof of the required number of iterations to achieve an acceptable confidence interval. The Board acknowledges TransAlta's concern that the results of individual iterations without convergent Monte Carlo simulation better reflects inherent variability in average pool prices and surplus/shortfall values. However, the primary purpose of the production simulation models in this proceeding is to assist in preparation of a representative forecast (expected values of pool price and surplus/shortfall) and hence the statistical distributions are of secondary interest only.

The Board, for the purposes of the refiling, will accept the confidence interval that results from the expected value (average result) of seven iterations of PROSYM. The Board considers that ENPRO would have to be run with considerably more iterations to obtain the same confidence

interval as the PROSYM results. The Board recognizes that there is a trade-off between the work associated with more iterations and the desired narrowing of the confidence interval. On balance, the Board considers that TransAlta should not be placed in the position of having to do more runs than EPGI. The Board notes that EPGI has been directed to carry out 14 runs of the PROSYM model for each year as a result of modeling both energy and ancillary services.

Accordingly, the Board directs TransAlta, in its refiling, to use 14 iterations of the ENPRO model to mitigate the non-convergent infirmity of the ENPRO model.

(D) Modeling Parameters

This section addresses issues in regard to some modeling parameters used by the Utilities in preparing their 1999 and 2000 forecast. In particular, issues respecting:

- Forced plus Maintenance Outage Rates and ACF,
- Output of generating units,
- Provincial load forecast,
- Price-responsive load, and
- Load forecast uncertainties

are addressed in the following sub-sections.

The following table summarizes the main characteristics of the generating units:

3. GENCO/TRANSCO/DISCO

(a) Generation

Unit	FMOR (%)	ACF (%)	MCR (MW)	ECR (MW)
Keephills 1	4.64	98.5	383	404
Keephills 2	1.82	98.8	383	404
Sundance 1	8.64	95.1	280	295
Sundance 2	4.69	95.9	280	295
Sundance 3	4.15	96.7	355	374
Sundance 4	3.43	97.2	355	374
Sundance 5	2.45	97.6	355	374
Sundance 6	3.58	97.9	366	385
Wabamun 1	1.69	95.0	64	67
Wabamun 2	1.86	94.0	64	67
Wabamun 3	9.12	89.4	140	148
Wabamun 4	9.20	87.1	280	295
HR Milner	10.80	94.1	145	152.7
Battle River 3	9.80	95.8	148	155.9
Battle River 4	10.00	97.4	148	155.9
Battle River 5	6.70	97.6	370	389.8
Sheerness 1	3.00	94.1	380	400.3
Sheerness 2	1.00	94.5	380	385.5
Rainbow 1	14.70	100.0	26	30
Rainbow 2	1.40	100.0	40	43
Rainbow 3	2.40	100.0	21.5	21.5
Sturgeon 1	75.00	100.0	10	11
Sturgeon 2	5.60	100.0	8	8.8
Genesee 1	2.387	99.75	386	406.6
Genesee 2	5.565	99.60	386	406.6
Clover Bar 1	5.636	98.77	158	170.7
Clover Bar 2	5.263	96.79	158	170.7
Clover Bar 3	20.365	99.48	158	175.9
Clover Bar 4	2.222	99.74	158	175.9
Rossdale 8	8.491	94.78	67	71
Rossdale 9	11.881	99.19	71	73
Rossdale 10	5.175	99.99	71	72

(i) FMORs and ACFs

The following issues were raised regarding Forced plus Maintenance Outage Rates (FMOR) and available capability factors (ACF):

- Is the use of a five-year rolling average appropriate?

- Should the calculation of FMORs be adjusted such that longer-than-normal outages, which may trigger applications for suspension of the obligation to pay the UOV (under the TSR), are removed?
- Is it appropriate to include maintenance outages as part of FMORs, as these are not totally random events, and also, should the effect of the Utilities practice to carry out some planned maintenance during forced outages be reflected in the forecast?

Is the use of a five-year rolling average appropriate?

Position of the Utilities

The Utilities agreed to calculate the 1999/2000 FMOR and ACFs, as in the past, using a five-year rolling average of actual performance statistics from 1993 through 1997.

EPGI submitted that, for the purposes of forecasting generation in 1999 and 2000, the FMOR and ACF used for EPGI's units were calculated, as they have in the past, using the most recent five-year rolling average of actual performance statistics from 1993 through 1997. EPGI noted that the five-year rolling average is a long-standing and well accepted practice which was relied upon in planning studies conducted by the EUPC during the 1980s for the purpose of forecasting the capability of the generating units on the Alberta system[29] and by the Board in EEMA proceedings. The Board endorsed the five-year rolling average in Decision U97065.

EPGI submitted that, since five years of data were not yet available for Genesee 1, an FMOR of 5% was assumed for the fifth year of data, which was consistent with the accepted practice for new generating units. EPGI indicated that the performance of its Genesee units in 1996 and 1997 is reflected in the five year rolling average unit statistics used in the model for 1999 and 2000.[30]

EPGI noted IPCAA's suggestion that the five-year rolling average of FMOR understates the level of generation to be expected from EPGI's units in 1999 and 2000, that the actual FMOR in 1996, 1997 and 1998 should form the basis for forecasting generation from the Genesee plant, and that incentives only existed from 1996 on, therefore only data from 1996 to 1998 should be used for the purposes of the generation forecast,[31] EPGI responded that the five-year rolling average provides a fair and reasonable basis for forecasting generation from Genesee in 1999 and 2000.[32]

EPGI noted that the high level of performance from EPGI's Genesee units over the past couple of years has been exceptional.[33] EPGI submitted that it would be unreasonable and inappropriate to use only two years of actual statistics for the purpose of generating a forecast of FMOR and

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[29] Tr. p.692
[30] Tr. p.242
[31] Tr. p.4428
[32] Exhibit 7, p.10
[33] Tr. p.242

ACF for 1999 and 2000.[34] The performance of the majority of EPGI's generating units in 1996 and 1997 does not reflect their expected performance over the long run. For example, Genesee 1 and 2, in 1996 and 1997 have average FMORs of only 0.8% and 3.7%, respectively, whereas the average for similar units on the AIES since 1985 is 4.2%.[35]

EPGI submitted that in recent years the statistics are not necessarily better, as performance incentive existed prior to 1996. Although the incentives were different, there were definite financial consequences for lower availability, since reduced availability resulted in higher cost generation or the need to purchase power from other Utilities.[36] Therefore, EPGI submitted that the forecast generation for 1999 and 2000, which is based on a five year rolling average FMOR, is fair and reasonable.[37]

EPGI also submitted that the evidence demonstrates that the methodology used by EPGI to forecast output from its generating units for 1999 and 2000 is based on long-standing practice which, together with EPGI's outstanding performance, has resulted in significant savings to customers. EPGI submitted that the Board should approve its generation forecast with the unit statistics based on the five-year rolling average methodology.

TransAlta indicated that since at least 1989, the EEMA forecasts were based upon a five-year average of generation statistics, which has proven to be equitable. The longer time period averages out the large deviations in performance that can occur as a result of the maintenance cycles. It also provides customers with the benefits that are available as a result of the long term, sustainable performance improvements.

Position of the Intervenors

ENMAX indicated that for 1999/2000, EPGI suggests that the forecast generation output should be based on the five year rolling average FMOR notwithstanding that generating performance from Genesee has exceeded the forecast in each and every year in the new structure. It noted that this is also TransAlta's position.

ENMAX submitted that the appropriate base for the forecast generation output should be the three years since industry restructuring, which represents the best approximation of the market for the test years. Using the five year rolling average skews the result as it includes years that do not approximate the current market conditions. In addition, use of the three year statistics recognizes the enhanced performance of the generators since 1996. ENMAX submitted that the Utilities have responded well to the incentives to improve the performance of their generating units even during periods when deferral accounts were in place. Since 1996 the average generating performance has exceeded the five year average in each year. Although the Utilities

[34] IPCAA-EPGI-16
[35] Exhibit 7, p.7
[36] Tr. p.400
[37] Tr. p.689 and p.402

continue to advocate the use of the five year average FMORs, the enhanced performance since 1996 should be recognized. It would therefore be appropriate to base the calculation of generating performance on the average FMOR of the three years since restructuring of the industry has taken place.

IPCAA indicated that another problem is that the Utilities used historical outage rates based on 1993-1997 – that is, three years under "Old World" conditions and only two years of operation under "New World" incentives.[38] 1998 actual performance was not taken into account in deriving the forecast 1999 numbers. Although the Utilities may not have had a full year of 1998 at the time they made their filings, they had most of the year, and in any event, the full year data are now available. As EPGI noted: "The five-year rolling average of forced outage rates used in the modeling runs are higher than the actual forced outage rates experienced in 1998."[39] IPCAA submitted that to be consistent, the year 2000 performance should have been based on the 1995-1999 average, using the forecast 1999 performance. Only by updating the numbers in this fashion will customers receive a share of the improvements in 1996-1998 relative to 1993-1995. IPCAA noted that further compounding the problem is an overstatement of the assumed forced outage rate for Genesee 1 as EPGI assumed a 5% FMOR for Genesee for the fifth year of data. IPCAA submitted that Genesee 1 is no longer an immature unit and thus this rationale should be rejected. For the last three years, the Genesee plant has had average output of 6,302 GWh per year.[40] However, EPGI claims that the plant can achieve output of only 6,035 GWh in 1999 and 6,112 GWh in 2000.

IPPSA/SPAA noted ENMAX's cross-examination of both EPGI[41] and TransAlta indicated that the Utilities forecast availability for 1999/2000 is below the average availability levels achieved since 1996. The Utilities argue that the inclusion of availability data for 1993-1995 is appropriate because some form of incentive did exist prior to 1996 to increase unit output.[42] From 1993-1995 the generation surplus on the system was greater than in 1996. Pool price, if it existed prior to 1996, would have been lower than in 1996 – where the average price was $14.42/MWh.[43] Pool price rose to $20.40/MWh in 1997 and increased to $33/MWh in 1998.[44] Pool price is forecast to further increase to $38.05/MWh in 1999.[45] IPPSA/SPAA indicated that the magnitude of the financial incentive for generator performance has dramatically increased since 1996 and that the Utilities have improved availability in response to these stronger financial incentives. EPGI, for example, has bettered its surplus/shortfall forecast each year since it began in 1996.[46] As a result,

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38 Ex. 2, EPGI Application, Appendix F, p. F-5.

39 Ex. 2, EPGI Application, p. 30.

40 Tr. p.4310. This takes into account normalizing 1996 from a 366 day year to a 365-day year. For a 366-day year this is equivalent to 3,610 GWh.

41 Tr. p.399

42 EPGI Tr. p.401; TransAlta Tr. p.1849

43 Power Pool Data

44 Tr. p.1850

45 Tr. p.1849

46 Tr. p.403

SPPA/IPPSA submits that the Board should reject the Utilities' premise that data from the pre-1996 period should be included in establishing availability levels for the 1999/2000 forecast.

Should the calculation of FMORs be adjusted?

Position of the Utilities

In response to an undertaking, EPGI provided a modified set of five-year rolling average statistics for EPGI's units, by adjusting the historical statistics to incorporate the potential effects from the application of a TSR. EPGI reviewed the actual forced outages of the 1993-1997 five-year rolling average to determine if there were any outages included in the historical data that would qualify for relief under the TSR. As a result of this review, EPGI concluded that the only outage that would qualify for TSR relief in either 1999 or 2000 would be an outage similar to a 49 day outage at Genesee 2 in 1994, arising from an LP rotor problem. The next longest outage at Genesee in the 93-95 period is less than a week. The longest outages at Clover Bar and Rossdale were each five-weeks, but these would not likely qualify as a TSR event, owing to the smaller size of the units and the higher variable costs relative to Genesee.

EPGI submitted that, if the Board elects to deviate from the five-year rolling average of actual FMORs, and elects to "truncate" certain actual FMORs, then the Board must grant such relief if such an outage was to actually occur, provided that the conditions of the TSR were met and the cause was beyond the owner's reasonable control. EPGI further submitted that the Board could not reject a TSR application on the grounds that event was not beyond what an owner was compensated to accept. If the Genesee 2 outage in 1994 was truncated for the reasons described above, then the question arises as to what extent it should be truncated. The outage in 1994 is indicative that large outages can and do occur and therefore it would be inappropriate and unfair to disregard such an event in its entirety. EPGI submitted that it would be more appropriate to truncate or reduce the length of the outage actually experienced to a point that is reflective of an outage that might still occur, but for which TSR relief would likely not be forthcoming. For example the Board could establish a threshold of say three weeks for a Genesee unit in 1999 or 2000, in which case EPGI would not be entitled to apply for TSR relief for any outage of less than three weeks, barring unforeseen circumstances. Therefore, the seven-week outage experienced in 1994 for Genesee 2 would be truncated from seven weeks to three weeks and the FMOR would decline from 15.2% to 7.5%. With a four-week threshold, the 1994 FMOR would be truncated to 9.4% or, alternatively, to 5.6% with a two-week threshold. EPGI believes that 5.6% is an lower bound for truncating the 1994 FMOR, which happens to correspond to the actual FMOR of 5.6% for Genesee 2 in 1996 that included an 11-day outage for which TSR relief was not obtained. If the actual FMOR for Genesee 2 in 1994 is truncated from 15.2% to 7.5%, the five year rolling average established for Genesee 2 in 1999 / 2000 would be reduced from 5.57% to 4.03%.

EPGI indicated that the Board should recognize that the impact of an outage on a utility is affected by a number of factors including the length of the outage, level of the pool price when the unit is unavailable, the size of the unit, the level of the UOP and the number of units. Any

occurrence must be judged on its own merits. For example, an outage that might not qualify at a low pool price may qualify for TSR relief at a higher pool price.

TransAlta noted that the Intervenors argued that the five year performance statistics include poor generation performance that would have been subject to relief under the TSR that is now available under the EU Act. However, in its evidence at Tr. p.3804-3807, TransAlta confirmed that there were no such situations in the performance statistics of its generating units that occurred prior to 1996 that would have been subject to relief pursuant to the TSR.

Position of the Intervenors

ENMAX submitted that, in examination by the Chairman, EPGI admitted that it may be appropriate to remove unusual events from the FMOR calculation.[47] ENMAX noted that EPGI indicated there were stronger incentives to improve generation output after 1996.[48] EPGI also suggested that a 60 day outage at Genesee would likely be beyond what EPGI is compensated and had such an outage occurred after 1996 it would probably have led to an application under the TSR.[49] ENMAX noted that TransAlta's average FMOR is based on statistics which include the outage to Keephills in 1997. For the same reason as noted above for Genesee, the use of average statistics requires an adjustment to remove aberrations which could be subject to the TSR.

Appropriateness of including maintenance outages as part of FMORs

Position of the Utilities

With respect to including maintenance outages in the FMORs, EPGI noted that in preparing the 1998 simulation, it noticed a number of forced maintenance outages in 1998 that appeared to be rescheduled to occur during the weekend. EPGI therefore removed these forced maintenance outages from the FMOR for the purpose of the 1998 simulation. The estimated amount of generation associated with a forced maintenance outage which appeared to be deferred to weekends in the 1998 simulation was approximately 367 GWh. The forced maintenance outages that EPGI assumed could be delayed to the weekend included only those of a duration where the unit could come off no earlier than Friday evening, and come back on no later than Monday morning.

EPGI noted IPCAA's claim that the Monte Carlo models have not accounted for "dynamic rescheduling," "which is the ability of plant operators to modify plans in light of actual circumstances," noting that EPGI had completed a two week minor turnaround on one of the Genesee units in 1997 during a forced outage.[50] IPCAA stated that plant operators could defer forced maintenance outages to some extent or reschedule planned outages to take advantage of

[47] Tr. p.1526
[48] Tr. p.1528
[49] Tr. p.1522
[50] Exhibit 138, Volume 2, Section 1, p.6

unexpected increases in pool prices due to plant outages.[51] EPGI responded, in rebuttal evidence, stating that plant operators have some flexibility to delay unplanned forced maintenance outages into weekends.[52] However, the impact on the surplus/shortfall position is relatively small. In conjunction with running its PROSYM simulation of 1998, EPGI noted the number of forced outage hours that were re-scheduled to occur on weekends. This improved EPGI's surplus/shortfall position in the 1998 simulation by approximately $0.7 million.

EPGI noted, however, that operators have little opportunity to reschedule planned outages to take advantage of either high pool prices or forced outages, due to the fact that planned outages are scheduled well in advance based on the availability of parts and the relatively limited skilled labor force required to perform the work. Even if a forced outage of sufficient length was to occur prior to a planned outage, it is very unlikely that a significant amount of the turnaround work could be advanced. EPGI noted that the actual amount of time required to repair units after a forced outage averaged one day for Genesee and three days for Clover Bar and Rossdale[53] which is insufficient time to reschedule a planned outage.

AE also confirmed that there is little opportunity to complete planned maintenance during forced outages.[54] It stated at the hearing that: "The issue around doing maintenance during forced outages, unless it is a very significantly extended forced outage, the likelihood that any significant maintenance similar to the turnaround maintenance can be done in that period is usually very small, because the crews aren't available, the material isn't necessarily available, and all of the different planning that goes into those activities is not complete."

TransAlta noted that IPCAA states at page 19 of its argument that the method of deriving the FMOR is incorrect because the utilities are able to complete the work planned for maintenance outage periods during forced outage periods. IPCAA also stated that the forced and planned maintenance outages have often been overlapped in the past. TransAlta agreed that overlapping, where possible, has been practiced for many years. Consequently, the ability of the utilities to overlap the outage periods to complete their maintenance has already been factored into the derivation of the historical FMOR rates, and the method to derive the FMOR rates used by the utilities is accordingly correct.

Position of the Intervenors

IPCAA submitted that the forecast output from coal plants is, for all practical purposes, a function of the input assumptions regarding outage rates, since the coal plants' running costs are so low that they will be dispatched all the time they are available.[55] Because the three Utilities agreed on common outage assumptions, their models produced virtually identical results for the

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[51] Exhibit 138, Volume 2, Section 1, p.10
[52] Exhibit 7
[53] EAL-EPGI-25
[54] Tr. p.4696
[55] Exhibit 97

low cost coal plants. IPCAA noted however that one problem is that the Utilities add the FMOR to the planned outages. It submitted that the FMORs are not additive because they can be, and often have been, overlapped. IPCAA noted that AE acknowledged that it is periodically able to perform aspects of planned maintenance when a unit has a forced outage, sometimes with the result that for that unit for that particular period, the full number of forecast planned and forced maintenance outage days are not all used. As well, AE considers that it is good operating practice to do planned maintenance if it can when a particular unit is down with an unexpected outage. It would make no sense to perform only the work needed to repair the forced outage and then take the unit down again in order to do planned maintenance as scheduled.[56]

As an alternative to the probabilistic modeling, IPCAA submitted a method that forecasts 1999 and 2000 results based on actual performance from 1996-1998, adjusted for differences in planned outage days. Mathematically, this is similar to the Utilities' approach, with the differences that:

- It takes into account explicitly, overlaps of forced and maintenance outage;
- It takes into account the differences between forecast and actual planned outages; and
- The forecast is based on three years of actual operation in the restructured industry, with the new incentives.

Board Findings

Is the use of a five-year rolling average appropriate?

The Board agrees with the Intervenors that the enactment of the EU Act, which resulted in the establishment of the Power Pool, has had a significant effect on the way the GENCOs operate their generating units compared to the "Old World" (or pre-EU Act) regime. It is clear that under the EU Act regime, the GENCOs have a strong incentive to operate their units at a higher level of availability than forecast, as a portion of the financial benefits of doing better than the forecast flow to the Utilities' shareholders.

The Board considers that it is inappropriate that the Utilities forecast the availability of their generating units using performance statistics that incorporate two years (of five) of data under the pre-EU Act regime. Instead, the Board finds that performance statistics recorded in 1996, 1997 and 1998, the time period since deregulation took place, are more appropriate to reflect performance during 1999 and 2000. Therefore, the Board directs the Utilities to recalculate FMORs and ACF using 1996, 1997 and 1998 data and to use these recalculated parameters in their refiling.

Should the calculation of FMORs be adjusted?

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[56] Tr. p.4624-4626. In 1996, EPGI had scheduled a two week minor turnaround. When the plant was taken out of service because of a forced outage, EPGI took the opportunity to do the planned work as well (see Exhibit 136, Volume II, Section 1, p.6 and Exhibit 7, p.10).

3. GENCO/TRANSCO/DISCO

(a) Generation

The Board notes that its decision, to direct the Utilities to recalculate FMORs and ACFs using only 1996, 1997 and 1998 data, resolves the issue of calculating FMORs and ACFs including outages which would have been granted relief under a TSR Application. The Board notes that no generating unit, currently forecast to operate in 1999 and 2000, has to date been granted relief from paying UOV under a TSR. Therefore, the calculation of FMORs and ACFs using only 1996, 1997 and 1998 data will be "pure" from outages which have been the subject of a TSR.

However, the Board notes that if a future GENCO GTA is required, the Utilities should exclude outages for which relief was granted under a TSR Application when calculating FMORs and ACFs.

Appropriateness of including maintenance outages as part of FMORs

The Board considers that there are two distinct issues in regard to the use of FMORs:

- One is the treatment of maintenance outages as random events in the forecast, and
- The other is that the Utilities perform some planned outage work at times of random outages and this is not accounted for in the forecast.

With respect to the first issue, the Board recognizes that the maintenance component of the FMOR is not totally a random event as some forced maintenance outages can be postponed to the weekend. The Board notes that by including all forced maintenance outages in the FMOR, the Monte Carlo simulation performed by either ENPRO or PROSYM would treat all forced maintenance outages as totally random events while, in reality, the Utility has the advantage of postponing forced maintenance outages to the weekend when pool prices are lower. However, the Board also recognizes that the models do not have the capability to differentiate between forced outages which must be done immediately and those that can be deferred to the weekend. Further, if forced maintenance outages that were deferred to the weekend were removed from the FMOR, the forecast would predict more-than-normal energy generation from thermal units, as not all maintenance outages would be accounted for. Therefore, the Board accepts the Utilities use of FMORs in their 1999 and 2000 forecasts adjusted to the three-year average and notes that the establishment of a pool price deferral account would compensate consumers for any potential discrepancies between forecast and actual pool prices due to the Utilities advantage of postponing maintenance outages to the weekend when pool prices are lower.

With respect to the second issue, the Board finds that the Utilities' practice of performing some planned outage work at times of random outages, when possible, is reasonable and commendable. The Board also agrees with the Utilities' position that it is not always possible to perform planned outage work at times of random outages as some of this work has to be scheduled in advance.

Nevertheless, the Board directs the Utilities, in their refilings, to avoid double counting forced outages and planned outages in their forecasts. The double counting can be avoided by either reducing forecast planned outages times by the three-year historical amount that planned outage

time has been reduced by forced outage time, or by reducing forced outages by the amount of time that forced outages have been reduced by planned outage time. The Board notes that the above adjustment will not address the advantage or disadvantage to Utilities respecting changes in the timing of planned outages. However, the establishment of a pool price deferral account would mitigate any advantage or disadvantage.

(ii) Output of Generating Units

The Maximum Continuous Ratings (MCR) and the Emergency Capability Ratings (ECR), also referred to as capacity above MCR, are two important parameters that define the output of generating units.

Position of the Utilities

The MCRs assumed by the utilities for their generating units, and shown on the table at the beginning of this section, were those approved by the Board in Decision U97065. The MCRs are unchanged from the Utilities' 1996 GTA Refilings with the exception of Battle River 1 and 2, which have been retired from service. There were no issues regarding the MCRs of generating units in this proceeding

TransAlta noted that in Decision U97065, Direction G-26, the Board considered that modeling capacity above MCR is essential to producing a proper generation forecast, and accordingly, developed two capacity increments above MCR. These two increments of capacity were included in the 1999 / 2000 generation forecasts.

The first capacity increment, for emergency conditions, is that capacity between the MCR and the ECR of the units, in accordance with the ratings shown in Decision U97065. The probability of achieving ECR is dependant upon two things: firstly, that the unit is capable of operating at MCR; and secondly, the probability that it can achieve ECR given that it can achieve MCR. TransAlta noted that in Decision U97065, the utilities were directed to use an appropriate heat rate for this first capacity increment. Since operation at ECR results in additional wear and damage to the units, leading to increased maintenance costs, the utilities offer the ECR capability at prices well above the UOP. To model the increased price in ENPRO, a fuel price was chosen for the capacity increment which would result in an incremental cost of about $100 / MWh, which appears, from an analysis of the Pool data, to be the level at which ECR capacity is generally being offered into the Power Pool.

The second capacity increment, for economic operation above MCR, was modeled as 0.4% of MCR, as calculated by the Board in Decision U97065.

TransAlta noted that EAL in argument, proposed terms and conditions under which TransAlta should be required to provide support services from capacity above MCR. During cross-examination, at Tr. p.2063, Mr. Way testified that reliance upon the capacity above MCR as operating reserve is inappropriate "due to its lower probability of being available." As stated at

Tr. p.2062, TransAlta is not convinced that the capacity above MCR qualifies as spinning reserve due to the low probability of achieving operation above MCR. Therefore, TransAlta submitted that it would be inappropriate for TransAlta to be required to provide system support services from capacity above MCR.

TransAlta submitted that if the Board deems that it is necessary to impose terms and conditions under which TransAlta is to provide system support services from the capacity above MCR, the provision of such service should be on a "best efforts" basis and without penalty in the event that the generating unit fails to respond as requested. It should be noted that TransAlta does offer the capacity above MCR into the energy market when it considers that the units are capable of operating above MCR, but these offers are made only on a "best efforts" basis.

EPGI noted that in Decision U97065, Direction G-31, the Board directed the utilities to develop two blocks of capacity above MCR. The first, referred to as the ECR block, would only be available during periods of system emergencies. The second block, referred to as "continuous operation above MCR", would be represented by increasing the MCRs of the units by 0.4%. Due to time constraints, the Board directed the Utilities to represent both blocks by a 0.5% increase in MCR for the purposes of the 1996 GTA Refiling. The Utilities have added two separate blocks of capacity above MCR for the purposes of the 1999/2000 GTA.

The ECRs were calculated factoring in the net probability of ECR (which is the product of the probability of reaching MCR and the probability that the unit can perform at ECR given that it is capable of performing at MCR).

EPGI noted the Board's Decision was silent on the offer price that should be used for each generating unit's capability. Given the increased maintenance costs due to additional wear and tear and the higher risk of the unit tripping, the Utilities offer the ECR capability of each generating unit at prices significantly higher than the UOP. For competitive reasons, the Utilities have not revealed their actual ECR offer price. As an alternative, it was simply assumed that all ECR blocks are offered in at $100 per MWh which is representative of the average offer price for ECR capability.

EPGI submitted that the increment for economic generation above MCR should be adjusted to – 0.8% for Genesee, 0.1% for Clover Bar and 0.2% for Rossdale, to more accurately reflect actual operating experience of the units.[57] No evidence was presented by Intervenors contradicting that these figures represent the appropriate adjustment to recognize the increment for economic generation above MCR. EPGI submits that these values should be taken into account if the Board determines that an updated generation forecast is required.

EPGI noted that the TA argues that the Board should direct the generators to provide capacity above MCR for the provision of operating reserve.[58] The TA suggests that owners be paid their

[57] BR-EPGI-4
[58] TA Argument, p.7

offering price if the ECR is dispatched, however the TA asserts that the ECR offers should be restricted to around $100/MWh.

EPGI indicated that there is no basis for the suggestion that offers should be limited as suggested by the TA. It is fair and reasonable that owners retain the right to offer generation above MCR into the pool at prices which they determine are reflective of the damage that occurs when units operate above MCR.

Position of the Intervenors

EAL submitted that it is required by the EU Act to make arrangements for an appropriate level of system support services as well as maintaining a certain level of reserve to discharge its function as WSCC interconnected control area authority. EAL indicated that many of the thermal generating units in Alberta have the ability to operate above MCR to the level of the ECR, in particular Keephills[59] and Genesee.[60] EAL submitted that, depending on real-time operating conditions some of this capacity would qualify as either spinning or non-spinning reserve. EAL proposed the capability of regulated generating units to operate above MCR for spinning and non-spinning reserve. EAL proposed that generators that are on line and have undispatched capacity above MCR, should be made available to provide spinning reserve. Capacity above MCR that is available within 10 minutes, but is not automatically responsive to changes in system frequency, should be made available for non-spinning reserve.

EAL proposed that where capacity above MCR is merely "made available" there should be no cost to the TA and hence no cost to consumers. The regulated GENCO would incur no cost unless the capacity above MCR was actually called upon. In that case it would be reasonable for the regulated generator to recover its costs. Providing the TA with access to the capability above MCR for purposes of operating reserve would provide significant benefits.

EAL indicated that, with prudent planning and co-ördination among EAL and the regulated GENCOs, the cost of reserve could be reduced without a reduction in system reliability and while maintaining the AIS obligations to the WSCC and interconnected systems. No additional cost would be imposed upon the regulated GENCOs unless the reserve was called upon. EAL stated that there would be cost saving from making available the capacity above MCR for purposes of reserve, as utilizing the capability above MCR for reserves reduces the need to constrain down other units from MCR.

EAL indicated that in addition to the substantial cost saving, reliance on undispatched capacity above MCR from units that are online would reduce the need to constrain down other units and would therefore increase the available energy supply to the market.[61] Since the increased supply would come from intra-Alberta units at a time when Alberta is generation constrained, increased

[59] Exhibit 81
[60] Exhibit 37
[61] Tr. p.2071

system security during periods of tight supply would result. The increase in intra-Alberta supply would reduce Alberta's dependence on imported energy. EAL indicated that had the capability above MCR been available for reserve since the beginning of the 1999/2000 tariff period a cost saving of approximately $9 million could have been achieved.

EAL clarified that it is not suggesting that the regulated GENCOs be required to perform beyond the capabilities of the generating units, but proposed that the units operate above MCR on an "as available" basis only. The operator of each thermal unit knows on a day-to-day basis whether a particular unit will be capable of providing capacity above MCR as reserve.[62] If a unit that would normally be able to operate above MCR were unable to do so for some reason, there would be no obligation on the GENCO to make that capacity available.

EAL submitted that the evidence demonstrates that EPGI makes capacity above MCR from Clover Bar available on days when its operator believes it would be reliable[63] and would be prepared to do so for other units under the same conditions.[64]

EAL noted that TransAlta agreed that if it could be demonstrated that capacity above MCR met the criteria, it could be counted as spinning reserve.[65] TransAlta also agreed that to ignore qualified operating reserve would be wasteful.[66]

EAL submitted that the Board, in Decision U97065, recognized the availability of capacity above MCR for emergency conditions, response to economic incentives, and for normal operating conditions around MCR. EAL indicated it is simply suggesting that the same recognition be given in the context of operating reserve.

EAL stated that amongst the GENCOs there appears to be reservations with respect to the reliability of capacity above MCR as reserve.[67] This concern appears to result from uncertainty, since the probability of capacity above MCR being available is lower than for capacity up to MCR. The probability that a unit is capable of reaching ECR, given that it is already capable of reaching MCR, was included in Exhibit 13. From Table 6 it can be seen that while the probability of attaining ECR is lower than that of attaining MCR, the additional capacity is expected to be available between 41.78% (Genesee 2) and 86.41% (Keephills 2) of the time.

EAL recognized that it would be unreasonable to expect capacity above MCR to be available as often as capacity below MCR, or to require a GENCO to commit to providing capacity above MCR for lengthy sustained periods. Under the EAL proposal, the operator would only be

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[62] Tr. p.2060
[63] Tr. p.645
[64] Exhibit 37
[65] Tr. p.2056
[66] Tr. p.2071
[67] Tr. p.644 and p.2058

assessing the availability of capacity above MCR for a 24-hour period. If the operator, determines that capacity above MCR would be available for a portion of that time then that is all that would be required. Consequently, for purposes of reserve, the period during which capacity above MCR might be dispatched is so small that capacity availability can be predicted with a reasonable and satisfactory degree of certainty. If the capacity above MCR were called upon, a generator would not be expected to maintain output above MCR for more than one hour. After a contingency, the TA has ten minutes within which to get the tie line flows back to schedule and this is done by deploying the reserves, which would include capacity above MCR. The TA then has one hour within which to re-establish reserve levels, which is accomplished by dispatching additional generation and allowing the generators that are operating above MCR to return to MCR output.

A concern was also raised that making capacity above MCR available as reserve would result in increased wear and tear on the generating units. If that capacity is actually called upon, which would be for limited periods of brief duration, EAL agrees that the level of wear and tear on the equipment would exceed that which would result from operations below MCR. However, these impacts would be addressed by the price at which this capability would be bid into the pool.

EAL stated that owners of generators should be compensated for the additional cost of operating above MCR. The price at which the capacity is offered to the pool would include this compensation, as would the price agreed to in an executed System Support Services Agreement. In the absence of an executed System Support Services Agreement, EAL believes it would be reasonable to pay the price at which the capacity above MCR is *bona fide* offered to the pool. Based on the evidence in the TransAlta Application that \$100 MWh appears to be the level at which capacity above MCR is generally offered to the pool, EAL would expect the offer price to vary around that number. If it appeared that there was gaming of the system, EAL would seek a further order from the Board. In the absence of an System Support Services Agreement dealing with this issue, EAL recommends that the operators of regulated generation units be required to advise the TA on a day-forward basis whether the capacity above MCR is expected to be available.

In summary, EAL recommended that generators that are on line and have undispatched capacity above MCR that is responsive to governor action resulting from changes in system frequency and dispatchable within 10 minutes should be made available to provide spinning reserve. Capacity above MCR that is available within 10 minutes but is not automatically responsive to changes in system frequency should be made available for non-spinning reserve.

Board Findings

The Board notes EPGI's request that the increment for economic generation above MCR should be adjusted to -0.8% for Genesee, +0.1% for Clover Bar and +0.2% for Rossdale, to more accurately reflect actual operating experience of the units. The Board also notes that there may be some merit in revising the Board's deemed +0.4%, based on actual experience. However, the Board considers that it should only change from the deemed increment of +0.4% to actual

experience for all regulated units at the same time. Accordingly, the Board considers that the increment for economic generation above MCR should be based on actual experience only if another GENCO GTA is required. For the purposes of the refiling, the Board directs the Utilities to use an increment for economic generation above MCR of +0.4% for all units.

The Board does not accept EAL's proposal that the GENCOs be directed to make capacity above MCR available for spinning reserve. Instead, the Board expects that the TA would develop a market for system support services such that GENCOs would have an incentive to offer capacity above MCR available for spinning reserve.

(iii) Provincial Load Forecast

The Utilities agreed to the following provincial load forecast:

	1996 Refiling (GWh)	1999 Forecast (GWh)	2000 Forecast (GWh)
APL DISCO	9,267	10,059	9,888
EP DISCO	6,283	6,504	6,532
TAU DISCO	21,797	24,300	24,260
ENMAX	6,770	7,421	7,620
Red Deer	499	510	517
Lethbridge	563	592	605
AIS – Direct Access loads		189	386
Losses	2,376	2,719	2,732
Total Load	47,555	52,294	52,540

	1996 Refiling (MW)	1999 Forecast (MW)	2000 Forecast (MW)
APL DISCO	1,268	1,418	1,416
EP DISCO	1,019	1,064	1,069
TAU DISCO	3,004	3,311	3,286
ENMAX	1,073	1,238	1,271
Red Deer	89	94	96
Lethbridge	100	109	112
AIS – Direct Access loads		26	49
Losses	441	395	398
Total Load	6,929	7,598	7,662

3. GENCO/TRANSCO/DISCO
(a) Generation

Position of the Utilities

The Utilities submitted a forecast of annual energy consumption on the AIS of 52,294 GWh in 1999 and 52,540 GWh in 2000. The 2000 energy forecast represents a 0.5% increase over the 1999 forecast. The increases in 1999 and 2000 are largely the result of forecast load growth within the AE, TransAlta and ENMAX service areas. The hourly load forecast is based on each entitled DISCO's forecast for its respective service area at the 25 kV interface. The DISCOs also forecast the portion of their load that will become Direct Access. The Direct Access load was removed from the DISCO's service areas since these customers will make their own purchases from the Power Pool. The forecast excludes load served by on-site generation since this load has no effect on the dispatch of regulated generating units. For this reason, on-site generation was also excluded from supply considerations.

The Utilities indicated that they used the actual 1996 hourly load shape for their 1999 and 2000 forecasts. They did not to use the 1997 load profile because it was affected by load interruptions, which are not an output of the production models.

The Utilities also indicated that transmission losses were forecast to average 5.2% in both 1999 and 2000. The 5.2% was based on the Funk & Associates Inc. report dated 30 March 1998 entitled Transmission Losses cash-flow Model prepared for EAL.

Position of the Intervenors

Intervenors did not submit evidence respecting the Utilities load forecast.

Board Findings

The Board accepts that the load forecast filed by the Utilities is reasonable. The Board notes that no party challenged the Utilities forecast or presented an alternative load forecast.

(iv) Price Responsive Load

The Utilities agreed to the following forecast of price responsible load:

Price at which load interrupts ($/MWh)	1999 Forecast (MW)	2000 Forecast (MW)
$45	96	85
$60	173	138
$200	308	302
$800	136	126
$999	38	30
Total:	751	681

Position of the Utilities

The Utilities indicated that the forecast of price responsive load was based on the add-up of each DISCO's price responsive load forecast for its own service area. The total amount of forecast price responsive load for 1999 and 2000 is similar to the amount included in the 1996 GRA Refiling.

EPGI noted that the amount of price responsive load in the 1999/2000 forecast exceeds the amount actually observed in 1998. This is due to the DISCOs projecting new price responsive load as the provincial supply/demand balance continues to tighten in 1999.

EPGI also noted that the forecast price at which customers are willing to interrupt is significantly higher in the 1999/2000 forecast. EPGI believes the higher price primarily reflects the replacement of load on DISCO interruptible rates (in which case the DISCO determined the demand-side bid) with customers that make their own decisions at which prices to respond.

TransAlta noted that IPCAA stated that the results of modeling Option 12 load show that interruptions far exceed the amounts available under contract. However, In Exhibit 134, TransAlta explained that if the contract maximums were to be exceeded, then TransAlta would extend the contracts with existing Option 12 loads, or would contract with new loads.

TransAlta also noted, respecting IPPSA/SPPA's argument, p.34-35, on Option 12 load, that IPPSA/SPPA have provided no evidence to support the conclusion that since the Option 12 load is no longer bid into the Pool by TransAlta, the pool price will be higher than forecast. Therefore, TransAlta submitted that there is no evidence that the modeling of Option 12 loads results in low pool price forecasts.

EPGI replied to IPPSA/SPPA claims that there is not enough data to provide an accurate forecast of the amount of price responsive load.[68] EPGI submitted that in making this claim, IPPSA/SPPA contradicts itself. IPPSA/SPPA cannot claim that there is insufficient data to quantify the price responsive load, yet also claim that the utilities over-forecast the amount of price responsive load in 1999 and 2000.

EPGI notes that the price responsive load used in the 1999 and 2000 generation forecast is based on the add-up of each DISCO's price responsive load forecast for its own service area. Although the total amount of forecast price responsive load for 1999 and 2000 exceeds the amount actually observed in 1998, the DISCO's indicated that they are projecting new price responsive load in 1999.[69] As well, EPGI noted that since the generation forecast was completed, the Power Pool has initiated its Voluntary Load Curtailment program.[70]

[68] IPPSA/SPPA Argument, p.35
[69] Exhibit 2, Appendix F, p.F-4
[70] Exhibit 57, Undertaking at Tr. p.1549-1552

EPGI also submitted that, contrary to the IPPSA/SPPA assertion that the "... directional bias in price responsive load forecast should not come as a surprise given the mathematical relationship between low price forecasts, underestimates of unit availability and improved utility earnings..." it has not "willfully" underestimated the pool price as claimed by IPPSA/SPPA.

EPGI responded to IPCAA claims that EPGI's forecast "...far exceeded the contracted maximum allowable hours of curtailment for TransAlta Option 12 loads." asserting that the impact on the pool price was minimal.[71]

Position of Intervenors

IPCAA submitted that, in modeling price responsive load, TransAlta and EPGI have far exceeded the contracted maximum allowable hours of curtailment for TransAlta Option 12 loads. TransAlta attempted to rationalize this result (essentially by squeezing two *contract* years of Option 12 curtailments in to a single *calendar* year).[72] However, in order to accomplish this feat in 1999, TransAlta would have had to initiate no curtailments in October through December of 1998 and there is no evidence to suggest that such was the case. In addition, TransAlta does not address other constraints in the Option 12 contracts such as the maximum number of call downs and the minimum and maximum call down periods. These additional constraints reduce the effective available amount of Option 12 "energy."

IPCAA referred to TransAlta's suggestion that the $45/MWh price responsive load was made up of 25 MW of Rate 720 and 60 MW of Option 21 load[73] submitting that there is no evidence to confirm that any of these loads do in fact curtail at $45/MWh and no basis to conclude that these customers would curtail for a duration of nearly 1000 hours (or 2-5 times as many hours as Option 12 customers).

IPPSA/SPAA submitted that the joint modeling assumptions used by the Utilities presume that 751 MW of price responsive load will be available in 1999. Moreover, significant blocks of this load are assumed to curtail at $45, $60, and $200 pool prices.[74] Pool price is assumed to be at or above the $45/MWh interruptible block for 997 hours in 1999. IPPSA/SPAA questioned what if the 96 MW interruptible block priced at $45/MWh does not exist? Pool Price would climb upward into the higher priced supply blocks for at least 253 hours. What if the 173 MW Option 12 interruptible block at $60 does not exist? Pool Price would spill upward into the $100 supply blocks for 271 hours. If only half of the 751 MW forecast price responsive load actually exists, how often will pool price rise above $500? Therefore, IPSA/SPAA submitted that the only hard data available to quantify price responsive load indicates that only 198 MW are being offered into the Pool.[75] None of this load is priced at $45. Moreover, the 180 MW of Option 12 load

[71] Exhibit 57, Undertaking at Tr. p.1545
[72] Exhibit 134, Response to Undertaking at Tr. p.3813
[73] Exhibit 87, Response to Undertaking at Tr. p.2201
[74] Joint Modeling Assumptions; Table 3 (see TransAlta GTA Binder 1; Section 2.2)
[75] Exhibit 112

presumed to be bid into the Pool at $60/MWh is no longer bid in by TransAlta.[76] It is now utilized by the System Controller for system emergencies and is no longer "economically interrupted" when pool price reaches $60.

IPPSA/SPAA also submitted that there is no way to accurately confirm whether the 751 MW estimate of price responsive load is even in the ballpark, as this load is not bid into the Pool. IPPSA/SPAA indicated one could set an upper limit on price responsive load by looking at much load is currently on rates that receive a pool price signal, namely TransAlta's Option 21, AE's Pool Access and Pool Opportunity Rates. IPPSA/SPAA submitted that, from the recent Phase II proceeding, it appeared that the load under those rates was well below 751 MW. However, there was no useful information on the record to indicate how much of that load, if any, curtails in response to pool price. Moreover, there is no hard data to indicate what price triggers the load to respond. In summary, IPPSA/SPPA submitted that there is neither enough hard data and analysis to quantify the amount of price responsive load nor the data to estimate at what price this load would curtail. Furthermore, the amount of price responsive load and the estimated price at which that load responds is clearly low and could easily lead to an understatement of pool price by $10-$20 in 1999.

Board Findings

The Board considers that the main issue regarding price responsive load is whether or not the forecast blocks and prices of price responsive load are reasonable. The Board notes that the forecasts of price responsive load were put together by the Utilities in mid-1998 by adding up each DISCO's forecast of price responsive load within its service area. Further, the Board notes that the prices at which each block is forecast to be interrupted were also based on the premise that most of the interruptible load would be called to be curtailed at the DISCO's request. The Board also notes that there have been some changes since mid-1998 that lends support to the Intervenors' position that the forecast of price responsive load is outdated. In particular:

- TransAlta's Option 12 loads, which were called to curtail at TransAlta's request based on a pool-price trigger, are now called to interrupt at the request of the System Controller only during system emergencies. This fact supports the Intervenors' position that this block of price responsive load would curtail at a price much higher than the price assumed by TransAlta of $60/MWh.
- Approval has been given to TransAlta and AE for tariffs that "flow through" the pool price directly to consumers who opt for these tariffs. Therefore, the decision to curtail load is no longer made by the DISCO but is now made by each individual customer. Consequently, it becomes very difficult to forecast the price at which price responsive load in these tariffs would curtail their load.

[76] Tr. p.3297

3. GENCO/TRANSCO/DISCO
(a) Generation

The Board recognizes that there is a great degree of uncertainty around price responsive load, but accepts the Utilities forecast as the best information available. The Board considers the following to be additional reasons not to change the Utilities forecast:

- The Option 12 loads, being interrupted only during system emergencies may tend to reduce price responsive load at the price forecast by the Utilities
- The ability for customers to curtail their own load may tend to increase the amount of interruptible load at lower pool prices
- The establishment of a pool-price deferral account should alleviate the majority of concerns related to price responsive load uncertainty and its effect on pool prices.

(v) Load Forecast Uncertainty

Position of the Utilities

EPGI submitted, in accordance with Direction G-18 of Decision U97065, an assessment of the effect of load forecast uncertainty on the generation forecast and net surplus/shortfall determination. EPGI indicated that the Utilities agreed to forecast their net surplus/shortfall position as if the actual load turned out to be 1.5% higher or lower in 1999 and 2000. EPGI's results are summarized in the following table.

	Base Case	Load 1.5% Higher	Load 1.5% Lower
1999			
Surplus/Shortfall ($ million)	(2.8)	(5.8)	(0.9)
Pool Price ($/MWh)	37.7	42.1	34.2
2000			
Surplus/Shortfall ($ million)	3.9	3.0	4.2
Pool Price($/MWh)	29.5	32.2	27.5

EPI noted that higher load increases the pool prices in 1999 but increases EPGI's net shortfall. A similar effect occurs in 2000, but there is less of an impact on EPGI's net surplus/shortfall position. A decrease in the load reduces the pool price as expected and improves EPGI's net surplus/shortfall position by $1.9 million in 1999 and $0.3 million in 2000.

TransAlta provided the following similar table with its assessment of load uncertainty.

	Base Case	Load 1.5% Higher	Load 1.5% Lower
1999			
Surplus/Shortfall ($ million)	32.95	32.12	32.76
Pool Price ($/MWh)	38.05	43.68	34.83
2000			
Surplus/Shortfall ($ million)	34.1	37.2	31.8
Pool Price($/MWh)	30.8	33.32	28.61

TransAlta indicates that in 1999 the pool price change is not symmetrical for equal load changes, increasing $5.6/MWh for a 1.5% increase in load versus decreasing $3.3/MWh for a 1.5% decrease in load. TransAlta's surplus position drops for either load scenario. In 2000, the pool price change is relatively symmetrical for equal load changes. TransAlta's surplus position increases when the load and pool price increase, and decreases when the load and pool price decreases.

Position of the Intervenors

IPCAA submitted that the Utilities' forecast assumed a fixed hourly load pattern and that this was based on 1996 because, according to TransAlta, "...1996 purchases provide a more typical shaping of the loads before interruptions than do the 1997 purchases . . . . The 1997 Power Pool purchases are affected by load interruptions, particularly at peak hours, and their use would distort the hourly shaping of the load forecast." However, IPCAA also submitted that the actual hourly loads are most certainly going to be different than the fixed forecast. This, too, will lead to a different pattern of pool prices and likely a different average pool price. EPGI's evidence showed that ±1.5% changes in load affect the average pool price by $3.5-$4.4/MWh in 1999.[77] The TransAlta evidence showed an effect of $3.2-$5.6/MWh for the same year.

Board Findings

The Board considers that the Utilities complied with the Board Direction to address load forecast uncertainty. The Board observes that a ±1.5% change in load has a significant affect on pool price and surplus/shortfall positions. Therefore, the Board considers that the establishment of a pool price deferral account would alleviate the Intervenors' concerns respecting pool price volatility due to load forecast uncertainties.

(E) Modeling Assumptions

This section addresses the way the Utilities modeled:

- the dispatch of thermal generating units,
- hydroelectric generation,

[77] Ex. 2, EPGI Application, App. F, p. F-4.

- imports of electricity from British Columbia, Medicine Hat, and Saskatchewan,
- the scheduled maintenance of thermal plants, and
- the variable cost of system support services, such as constrained on generation for transmission support, constrained on and down operation in providing operating reserve and constrained down operation for automatic generation control (AGC).

in their 1999 and 2000 forecasts.

(i) Dispatching of Thermal Generating Units

Position of the Utilities

The Utilities indicated that the modeling of the dispatch of generating units was based on offering the output of each unit, up to its MCR level, at a cost equal to each unit's UOP.

EPGI further indicated it had to carry out a preliminary set of productions runs to establish the average heat rate for EPGI's gas-fired units. The average heat rates were then adjusted to account for out-of-merit generation and the net heat rate was used to establish the unit obligation price (UOP) for Clover Bar and Rossdale, which were subsequently used in the final set of production runs.

TransAlta submitted that since 1996, TransAlta's thermal generating units, with the exception of unit ECR capability, have been offered to the Pool at their marginal cost of generation. Further, TransAlta submitted that, through monitoring of pool offers and settlement data since 1996, TransAlta has been able to infer that non-TransAlta thermal units were also offered predominantly at their marginal cost of generation.

The Utilities, therefore, submitted that their modeling of thermal units dispatch was appropriate.

The dispatching of generation above MCR, up to ECR, was assumed to be offered to the pool at prices ranging between $80 and $199 per MWh. This incremental ECR amount was based on the Utilities' experience gained since 1996, when the pool was established, and their assessment of the price at which they believe the offer should be to compensate for the risk associated with operating a unit above its MCR. To model this higher-price offer, the Utilities indicated they modified each unit's cost curve such that the production cost would be in the $80 to $199 per MWh range when a unit is dispatched above its MCR.

Positions of the Intervenors

Intervenors addressed the issue of offers into the pool at prices other than the units' UOPs but in the context of Market Power and in support of the establishment of deferral accounts. Intervenors did not propose any alternative ways of modeling the dispatching of thermal units in the energy simulation models.

Board Findings

The Board notes TransAlta's submission that thermal units are predominantly being offered at the variable cost of generation. However, the Board also recognizes that, at each hour, the owner of the marginal unit setting the pool price has an incentive to offer the output of that unit at prices above the unit's variable cost of generation. This behavior is not captured by the generation models used by the Utilities and may be another source of the discrepancy between forecast and actual pool prices.

The Board notes that the Utilities' models were the only models used for producing the 1999 and 2000 forecasts. The Board was not presented with any other alternative respecting the dispatch of thermal units. The Board, for the purposes of the refiling, will accept the way the Utilities modeled the dispatch of generating units, i.e., offered at the variable cost of generation up to MCR, and the output between MCR to ECR offered at prices ranging from $80 to $199 per MWh. The Board notes that issues regarding the offering of the output at prices other than variable costs, and their effect on pool prices, will be addressed in the GENCO Deferral Accounts, Part 1–General, Section 3(a)(4) of this Decision.

(ii) Modeling Hydro Electric Generation

The different hydroelectric modeling technique used by ENPRO and PROSYM is the source of significant discrepancies in the amount of surplus (or shortfall) forecast by the Utilities for 1999 and 2000. This subsection addresses the issue of hydro generation from a purely modeling point of view and presents the Board findings respecting the modeling techniques used by the Utilities.

Position of the Utilities

The Utilities agreed on the input assumptions used to model hydroelectric generation[78]. They indicated that their models first dispatch the must-run portion of the hydro capacity to satisfy river flow requirements. The main disagreement is in the technique used by each model to schedule the hydro energy that is available above the minimum hydro-energy generated to satisfy river-flow conditions.

Position of EPGI

EPGI indicated that PROSYM allocates hydro (above the minimum hydro generated to satisfy river-flow conditions) on a weekly basis and optimizes hydro dispatch by scheduling the weekly-allocated amount during the hours of minimum reserves in each week. EPGI also indicated that this optimization required foresight of the availability of other sources during the week of hydro dispatch. EPGI indicated that PROSYM's hydro model produced hydro-generation surplus/shortfalls that were more attuned to hydro surplus/shortfalls seen on an actual basis[79] and

[78] Table 12 of the Joint Utility Generation Modeling Assumption Package.
[79] 3(a)(1)(B) - Simulation of Actuals.

that this was an indication that PROSYM's technique replicates the intervention of the human hydro-scheduler better than ENPRO, the model used by TransAlta.

EPGI replied to EAL's argument regarding the suggestion that it is necessary to model hydro generation by river system and responded that, although this may provide some improvement in the model, the improvement would not be material. This is demonstrated by the results of EPGI's 1998 simulation which showed that the simulated aggregate hydro surplus/shortfall closely matched the actual hydro surplus/shortfall. Also, respecting EAL's suggestion that EPGI should model hydro in two separate blocks, including a must run block and a price responsive block to ensure that the forecast hydro output reflects the long-term average output, EPGI submitted that the manner in which PROSYM models hydro is consistent with EAL's suggestions as described above. There is a must run hydro block and a block that is dispatched to maximize revenue. PROSYM ensures that the forecast output matches the long-term average output which is a parameter in the model.

Regarding EAL's request that the Board direct the Utilities to produce a study of the historical hourly contribution to AGC, Spinning Reserves, and Operating Reserves from hydro and to use the results of this study to determine appropriate values for the maximum hourly contribution of hydro to operating reserve throughout the year, EPGI submitted that it failed to see the usefulness of the GENCOs performing such a study, given that this is the last generation GTA and the PPA regime will come into effect on 1 January 2001. EPGI submitted that it would be more appropriate for EAL to conduct such a study as, unlike EPGI, the TA will appear before the Board in regulatory proceedings on an ongoing basis in the future.

In response to arguments that EPGI's generation forecast understates pool prices since hydro offers cannot set the pool price, EPGI submitted that the impact is immaterial given the results of the 1998 simulation.

Position of AE

AE corroborated EPGI's testimony regarding PROSYM's hydro modeling and added that PROSYM does not carry unused energy from one week to the next one, therefore, the foresight implied in the hydro optimization model did not extend beyond a week.

Position of TransAlta

TransAlta explained that ENPRO creates a preliminary hourly system price profile for each month by modeling a "typical" week in each month. ENPRO then formulates a guideline for hydro dispatch by allocating hydro energy into the highest price hours, following the hydro constraints on availability. Next, ENPRO simulates the entire year hour by hour, using the hydro dispatch guideline developed for each month. TransAlta explained that, as not every week in any given month will look exactly like the "typical" week used to generate the hydro dispatch guideline, the modeler can give ENPRO a degree of flexibility around the hydro dispatch guidelines. The model also determines a "trigger price" for hydro energy which is based on the guideline price for each hour. TransAlta explained that a situation can arise where a "typical"

week which is not very representative of a forecast week is encountered early on in a month, and if the model is given a lot of flexibility to dispatch more hydro in response to high system prices, then ENPRO can run out of energy later in the month. In the real world, system operators lacking perfect foresight could run into the same situation. TransAlta pointed out that the ENPRO hydro model focuses on the pool price when it is formulating the hydro dispatch, and submitted that the model is consistent with how a human hydro scheduler would dispatch hydro generation. TransAlta was therefore satisfied with its hydro generation forecast.

In response to IPCAA's argument, TransAlta submitted that the amount of hydro generation in 1998 was significantly higher than the amount that is forecast for 1999, and that the hydro runoff that led to the increased generation came in a manner that allowed most of the increased generation for 1998 to be produced in the high price periods. Therefore, a direct comparison of the forecast hydro surplus for 1999 with the actual surplus for 1998 is invalid. The 1999 forecast surplus and the 1997 actual surplus are both in the order of $4 million, and therefore the assertion that the forecast surplus is lower than the actual surplus is not valid. TransAlta also stated that the forecast revenue from hydro was in the range that had historically been seen in the 1996 to 1998 period, and that the revenue from hydro that was forecast by EPGI exceeded the historical revenue.

In response to EAL's argument, TransAlta submitted that EAL did not provide sufficient reasons to support its suggestion that hydro offers should be modeled in multiple price blocks. TransAlta explained that, since each run of the production models is forecasting different generating unit availability for each hour, and therefore different pool prices, the multiple price blocks for each run would have to be different in order to get the most effective hydro dispatch. It is difficult to imagine that a better forecast will be achieved by having a modeler develop the multiple price blocks which would be input into the models, rather than to use the well developed and tested hydro dispatch models that have been used in the production and cost forecasting models.

TransAlta responded to EAL's argument that the aggregation of the hydro units must be restricted as much as possible and, as a minimum, the modeling of hydro should be by river system, be stating that the methodology of modeling the hydro generation as a single resource has been accepted by the Board in the past. TransAlta also indicated that EAL did not raise the issue in its Information Requests or during cross-examination, and has provided no evidence to support its argument that a change in hydro modeling is warranted and essential. Therefore, TransAlta submitted that the Board should not accept EAL's recommendation to restrict the aggregation of the hydro units.

Finally, respecting EAL's recommendation that the Board direct the three Utilities to adopt a common methodology without mandating a specific modeling tool, TransAlta submitted it failed to see the value of this suggestion given that generation will no longer be regulated in the same manner as the current proceeding.

3. GENCO/TRANSCO/DISCO
(a) Generation

Position of the Intervenors

Position of IPCAA

IPCAA submitted that, as the output from hydro plants is limited and they cannot be run at maximum output all hours of the year, TransAlta schedules more output at times of higher pool prices. The result, as expected, is that the average revenue realized on hydro generation is greater than the average pool price. Further, IPCAA submitted that, as the system becomes "tighter," there would be an increasing number of hours of higher pool prices and it is likely that the ratio of the hydro average pool price to the all-hours average pool price will become even higher. Therefore, IPCAA submitted that it is surprising that TransAlta is forecasting such a low hydro surplus for 1999 and a net shortfall in 2000.

IPCAA summarized the hydro surplus/shortfall forecast by each Utility in 1999 and 2000 in the following table:

	1999		2000	
Forecast by	Generation Energy	Surplus ($Millions)	Generation Energy	Surplus ($Millions)
AE	1,666 GWh	$15.3	1,666 GWh	$9.3
EPGI	1,666	12.8	1,667	8.1
TAU-G	1,661 GWh	$ 3.8	1,658 GWh	$(3.4)

IPCAA also submitted the following table showing actual hydro surplus since 1996:

Year	($ Millions)
1996 GTA	$1.80
1996 Actual	3.40
1997 Actual	4.30
1998 Actual (11 mos.)	$11.20

IPCAA submitted that TransAlta's forecast should not be accepted since it predicts a lower hydro surplus in 1999 (and a shortfall in 2000) than actual surpluses realized in 1997 and 1998. IPCAA further submitted that because the output of the hydro plants is timed to take advantage of higher pool prices, the average hydro pool price has always exceeded the all-hours average pool price. Therefore, IPCAA submitted that TransAlta's model underestimated the ability to move hydro into higher priced periods in the 1997 backcast and this continues in its current forecast. TransAlta's evidence is that in 1999 they will receive a lower average pool price from hydro, as a percentage of average system pool price than they achieved in either 1997 or 1998.

IPCAA also submitted in reply argument that neither ENPRO nor PROSYM allow for hydro resources to set the pool price. It is equally clear that the actual practice is to offer hydro to the pool in a manner that can in fact set the pool price. The fact that hydro offers can set the pool

price is a fundamental difference between the generation forecasts and the real world experience. Moreover, that difference can only result in an upside to TransAlta as the operator of the hydro resource.

Position of IPPSA/SPPA

IPPSA/SPPA submitted that if hydro modeling is the most significant difference between ENPRO and PROSYM, then determining the accuracy of the hydro modeling is critical to determine which surplus/shortfall estimate is more accurate. IPPSA/SPPA submitted a table analyzing forecast versus actual data for January, February, and March of 1999 and concluded that the data indicates that PROSYM has done a superior job of estimating hydro dispatch than ENPRO.

Position of ENMAX

ENMAX submitted that a major variable causing differences in forecast surplus/shortfall is the modeling of hydro generation surplus revenues. TransAlta stated that the hydro generation selling price as a percent of average pool price was 115% in 1996; 125% in 1997 and 124% in 1998. For its forecast TransAlta has used a hydro selling price forecast of $45.80/MWh in 1999 (or 120% of average pool price) and EPGI has used an even higher price at 135% of average pool price. In 2000 the average selling price for hydro generation as predicted by TransAlta is $31.70/MWh versus an average pool price of $30.80/MWh, a mere 103% of average pool price. ENMAX indicated that TransAlta's hydro forecast does not seem intuitively reasonable.

Position of EAL

In regard to the hydro modeling EAL submitted that :

- the hydro system has not been modeled in sufficient detail,
- reserve requirements from hydro have not been adequately defined,
- the amount of reserves available from hydro has been overstated,
- it is inappropriate to model hydro offers at UOP, instead the hydro offers should be modeled in multiple price blocks so the modeled dispatch properly reflects must run requirements, the price responsiveness of the Hydro resource, and the weekly, monthly and annual energy constraints.

EAL submitted that the primary difference between the three forecasts relates to the way the hydro units are dispatched. The modeling performed by EPGI shifts the available hydro energy to the higher priced periods more successfully than the modeling by TransAlta. As a result, EPGI is predicting higher hydro revenues and a lower overall pool price than TransAlta.

EAL also submitted that the differences in the hydro dispatch affects the dispatch of other units and affects the cost of acquiring operating reserves. Because hydro capacity that is on line but not dispatched is generally available to the TA for Spinning and Non-Spinning reserves without additional cost, (while reserves acquired from the thermal generators are priced at the difference

between the Pool Price and the unit UOP i.e. lost opportunity cost) differences in the hydro dispatch can materially affect the forecast cost of System Support Services. While all the models recognize the uncertainty in generator forced outages and derates, these factors are not the only sources of forecast uncertainty. The load forecasts are uncertain as well as future natural gas prices, hydro energy available, and import and export prices. As well, planned turnaround schedules can and do change several times a year. None of the models used by the Utilities recognize these uncertainties.

With respect to modeling, EAL believed, and recommended to the Board, that the focus should be on identifying a consistent methodology, not merely identifying consistent inputs. PROMOD, ENPRO and PROSYM are not materially different in the manner in which they model system operation. To address deficiencies in the models, most results are post processed. For this reason EAL recommends the Board direct the Utilities to adopt a common methodology without mandating a specific modeling tool. The need for a common methodology does not preclude the adoption of a different methodology in the future in response to improvements in forecasting technology or methods. Furthermore, EAL believes that it is essential to a successful methodology that aggregation of hydro units must be restricted as much as possible. As a minimum, hydro should be modeled by river system. The hydro river systems must be modeled with appropriate values for MCR capability, must run levels, reserves, and energy limitations. Modeling the Brazeau plant separately is critical.

EAL submitted that modeling the thermal offers at UOP is reasonable. However, it has been demonstrated that the hydro generation is generally not offered at its UOP. Furthermore, the hydro offers do set the Pool Price at times. Because of this, modeling the hydro offers at the hydro UOP is inappropriate. Hydro is an energy-constrained resource with a significant amount of capacity. The price at which the hydro energy is offered into the system varies to regulate the flow of water such that various constraints are satisfied and the value of the resource is maximized.

EAL further submitted that, to satisfy the various constraints of the system, the hydro offers should be modeled in at least three price blocks. Must run amounts should be modeled at the UOP of hydro to insure dispatch. To insure hydro units will respond to high pool prices and periods of supply shortfalls, some of the hydro should be offered at a price that is greater than the highest thermal unit UOP of the thermal units. The remaining hydro units should be offered at a price that will result in both the annual and monthly energy from hydro units approximating the long term average.

EAL also submitted that, because operating reserves are procured preferentially from unutilized hydro capacity over constraining down thermal units, it is necessary that the maximum level of reserves that can be provided by hydro units be estimated accurately. The three generating Utilities agreed to a 300 MW maximum hourly contribution which hydro generation can contribute to operating reserve. In EAL's opinion the maximum hourly hydro contribution to operating reserve is lower than 300 MW. The amount of MWh constrained down for AGC on

thermal units was significantly higher in 1998 than what has been forecast for 1999 and 2000. The increased use of thermal units to provide AGC is evidence that less AGC is available from hydro units than what is forecast. Therefore, EAL recommended that the Board direct the Utilities to produce a study of the historical hourly contribution to AGC, Spinning Reserves, and Operating Reserves from hydro and to use the results of this study to determine appropriate values for the maximum hourly contribution which hydro can contribute to operating reserve throughout the year.

Board Findings

In deciding whether to accept the PROSYM or ENPRO hydro simulations, the Board must consider the merits of each model and also compare predictions made by these models with actual hydro results. In particular, the Board considers that one key indicator is the forecast hydro surplus produced by these models compared to actual hydro surpluses recorded in the past.

The main thrust behind the merits of each model's treatment of hydro was the degree of foresight that these models have regarding the unavailability of other resources and their consequential effect on pool prices. Both models are able to view the pattern of outages of other resources and to schedule more hydro during the periods when the other sources are unavailable and pool prices are higher, and to schedule less hydro during periods of high availability and lower pool prices. This modeling technique is intended to replicate as closely as possible the intervention of the human hydro-scheduler and his ability to optimize hydro generation. PROSYM carries out a weekly hydro optimization. The modelers assign a weekly allotment of hydro energy and PROSYM optimizes that weekly hydro energy only during the week. The weekly-allotted energy is used up during the week and there is no hydro-energy transferred to, or borrowed from, adjacent weeks. ENPRO seems to carry out a hydro optimization in a somewhat similar fashion to PROSYM but on a monthly basis. However, the modelers can control, and limit, ENPRO's flexibility to move hydro energy from periods of low pool-price to periods of high-pool price within each month. TransAlta testified this control was used to avoid situations where ENPRO may dispatch more hydro at the beginning of a month, in response to high system prices, and then run out of energy later in the month.

In reality, as hydro is an energy-limited resource, the human hydro-scheduler schedules more output at times of higher pool prices at the expense of less output during low pool prices. Consequently, as the pool price is generally higher during times of thermal unit unavailability than during thermal unit availability, (the so-called asymmetry effect), hydro generation has always been able to achieve a surplus and never a shortfall since 1996. As the system becomes "tighter," and therefore the asymmetry effect more pronounced, there would be an increasing number of hours of very high pool prices that would likely enhance the hydro surplus. Therefore, the trend of actual hydro surpluses recorded since 1996 tend to support a forecast that would show high hydro surpluses such as those provided by EPGI and AE.

Although TransAlta counters that actual surplus in 1998 was higher than expected due to higher-than-average precipitation, and therefore more hydro generation, TransAlta's ENPRO hydro

results appear too conservative. In particular, ENPRO predicts a hydro shortfall for the year 2000, even though total annual hydro generation is the same in 1999 and 2000.

The Board believes this is an indication that TransAlta modelers did not give ENPRO enough flexibility around the hydro dispatch guidelines to allow it to move more hydro generation to hours of higher pool prices. In reality, however, a human hydro scheduler would optimize hydro generation such that a surplus would likely be achieved.

The Board also notes that hydro generation was forecast to be about 1,660 GWh in both 1999 and 2000. This amount corresponds to the 20-year hydro average and also corresponds to the total annual hydro obligation amount set in the regulations. Therefore, even if the models were so simplistic as to schedule hydro just to meet the hydro obligation in each hour, the result would be neither a hydro surplus nor a hydro shortfall and certainly never a significant hydro shortfall as TransAlta has forecast. Therefore, the Board considers TransAlta's $3.4 million forecast shortfall in 2000 to be unrealistic.

Judging from actual results, the human hydro-scheduler appears to have sufficient weekly foresight to consistently achieve hydro surpluses. PROSYM's weekly foresight appears to mimic the human hydro-scheduler better than ENPRO. The Board is persuaded by the evidence submitted by EPGI and AE that PROSYM's hydro simulation produces hydro results that are closer to those achieved in reality by the intervention of the human hydro scheduler than ENPRO. Accordingly, the Board directs EPGI, in its refiling, to submit the results of the re-runs of PROSYM incorporating all of the Board's findings in this Decision respecting modeling. EPGI's re-runs will be used to set the baseline forecast hydro surplus/shortfall.

TransAlta is directed, in its refiling, to use the EPGI re-runs in TransAlta's refiling of forecast hydro surplus/shortfall. TransAlta is also directed, in its refiling, to submit the results of the re-runs of ENPRO incorporating all of the Board's findings in this Decision respecting modeling.

The Board will not use ENPRO's hydro surplus in setting the baseline forecast hydro surplus/shortfall, however the Board will use ENPRO's and PROSYM's thermal surplus in setting the baseline forecast thermal surplus/shortfall. The Board expects that there will be co-operation and information sharing between the GENCOs as required to complete the Board directed modeling re-runs.

In regard to EAL's recommendations, the Board considers that EAL's hydro modeling suggestions and its recommended study, to determine appropriate values for hydro contribution to operating reserve, have merit under the current regulated environment. Such recommendations and study would be useful to improve the hydro forecast and surplus/shortfall calculations in a future GTA. However, the Board accepts the Utilities' submission that this may be the last GTA where surplus/shortfall calculations are necessary, as obligations and entitlements will disappear under the PPA regime commencing in 2001. Should the PPA regime not proceed as scheduled and/or should a future GENCO GTA still be necessary, the Board would consider EAL's

recommendations at that time. The Board is also satisfied that, for this refiling, the establishment of a GENCO pool price deferral account would obviate the need to direct the Utilities to implement the hydro modeling suggestions made by EAL.

(iii) Scheduled Maintenance of Thermal Plants

The maintenance schedule is used in the energy production models to account for times when generating units are unavailable due to planned maintenance. The Utilities prepared maintenance schedules (also referred to as turnaround schedules) for their thermal plants in 1999 and 2000 and agreed to use these schedules in their generation models to prepare their 1999 and 2000 forecasts. Table 12 of the Joint Utility Generation Modeling Assumption Package presents the agreed turnaround schedules. There are some variations between the schedule used by TransAlta and EPGI.

Position of the Utilities

TransAlta submitted that it indicated to the other Utilities in October 1998 that the Wabamun turnarounds would be revised. Specifically, the Wabamun 3 turnaround in 1999 would take place from 11 September to 9 October, instead of from 13 March to 10 April as originally planned. The Wabamun 4 turnaround in 1999 would start on 6 March and end on 15 April, instead of from 9 October to 15 October as originally planned. TransAlta indicated that these late changes were not reflected in the generation forecast of AE or EPGI.

Position of the Intervenors

IPCAA submitted that the Utilities used the same input data for their models, but they differed in a number of factors including the schedule for Wabamun turnarounds. Further, IPCAA submitted that the models do not incorporate significant aspects of real-life behavior, such as operator decisions to defer maintenance outages and/or reschedule planned outages. EAL submitted that planned turnaround schedules can and do change several times a year and that none of the models used by the Utilities recognize this uncertainty.

Board Findings

The Intervenors raised the issue of using a maintenance schedule in the forecast that may be different from the actual maintenance schedule performed by the Utilities. The Board addressed this same issue in the 1996 GRA. In Decision U97065, the Board recognized that unplanned (random) outages of power units could occur any time during the year and that such occurrences could trigger a utility to reschedule its planned maintenance. The Board reiterates its position that actual planned outages occurring at times different from the maintenance schedule used in the forecast are unavoidable. However, since rates are approved on a prospective basis, only the forecast maintenance schedule need be considered by the Board.

The Board considers that the Utilities should use a common maintenance schedule and therefore, directs EPGI to re-file its forecast with the planned turnarounds for Wabamun as submitted by TransAlta.

(iv) Modeling System Support Services

The variable portion of system support services can be divided into the following three components:

- variable payments for constrained on generation for transmission system support.
- variable payments for spinning reserve to provide for the loss of other units on the system.
- variable payments for automatic generation control (AGC) which allows the System Control Center to automatically adjust a unit's output to meet demand changes.

The following table summarizes the variable system support (or ancillary) services revenue forecast to be received by the generating Utilities:

1999 ($ millions)	**AE**	**EPGI**	**TAU**
Constrained on Generation for Transmission System Support	0.4		
Constrained on/down Generation for providing Operating Reserve	3.5	11.9	2.0
Constrained down Generation for providing AGC	4.3		3.3
Total Variable System Support Services	**8.2**	**11.9**	**5.3**
2000 ($ millions)			
Constrained on Generation for Transmission System Support	0.4		
Constrained on/down Generation for providing Operating Reserve	1.0	9.3	2.0
Constrained down Generation for providing AGC	3.2		3.3
Total Variable System Support Services	**4.6**	**9.3**	**5.3**

The generation models used by the Utilities commit units based on the rules of economic dispatch and, in carrying out this process, they develop the "merit order." This is a list identifying the order in which units are to be dispatched. In the merit order, operating units are arranged such that the cheapest unit to operate is dispatched first, the second cheapest unit is dispatched next, and so on, until the unit most expensive to operate is dispatched last. However, in a power system as large as Alberta's, there are always exceptions to the merit order. This is the case for generating units that, although expensive to operate, have to run on a continuous basis to provide reliability of supply in areas where the transmission system is weak. It is, therefore, the TA who requires that these units operate out of merit (i.e., not in accordance with the merit order) and who also pays the GENCOs the costs associated with running units out of merit. Out of merit operation is also referred to as "constrained on generation for transmission system support." The compensation for out of merit is calculated by the difference between UOP

and pool price times the transmission dispatched MWs. This section addresses the method and the accuracy of the Utilities' calculations of out of merit costs.

The Utilities also provide operating reserve and AGC, which are paid for by the TA as part of system support services. The main components of the operating reserve and AGC costs are the fuel and opportunity costs. When a generating unit is designated to contribute to operating reserve, a portion of its output capacity is kept in reserve in case of need. Similarly, a portion of the output of a unit on AGC is held back to give its automatic controls the necessary freedom to make generation adjustments in accord with the constant variations of the electric load to maintain the control margin. Therefore, there are some variable operating costs and opportunity costs attributable to the missed sales opportunities associated with units on AGC and units contributing to operating reserve. The fuel and opportunity costs are calculated by the difference between pool price and UOP times the merit dispatch MW minus the actual dispatch MW. This section also discusses the methodology and the accuracy of the calculations of the fuel and opportunity cost component of providing operating reserve and AGC.

Position of the Utilities

Position of EPGI

EPGI submitted it has built into its settlement model the calculation of the forecast variable operating reserve payments from the TA. For each hour, the settlement model determines whether EPGI's generating units are operating out-of-merit to provide operating reserve. In these cases, EPGI is forecast to receive a payment for the difference between variable costs and pool receipts. The model also determines whether EPGI's units have been backed down to provide spinning reserve rather than energy. In this case, EPGI is forecast to receive a lost opportunity payment which is equivalent to the Unit's 10 minute spinning reserve capability multiplied by the difference between pool price and UOP. These payments are forecast to be $11.9 million and $9.3 million respectively in 1999 and 2000.

In response to EAL's argument that the Board should deem system support services payments of $13.6 and $11.7 million for EPGI in 1999 and 2000 respectively, EPGI responded that it would be inappropriate to deem operating reserve payments that have not been output from a generation forecast, as the fuel costs and lost opportunity costs incurred to provide operating reserve in accordance with the deemed payments would not be reflected in the surplus/shortfall forecast.

EPGI also submitted that the TA's view that operating reserve payments should increase with pool prices is too simplistic. EPGI referred to Dr. Bridgeman's testimony that the amount of variable system support services revenue can decrease with higher pool prices[80], stating that the addition of Rainbow 4 and Fort Nelson is forecast to reduce the need for Rainbow 1 through 3 to provide transmission support in northwest Alberta. As a result, these units are free to provide spinning reserve which reduces the need for Rossdale and Clover Bar to provide spinning reserve through constrained down operation. EPGI concluded that there is no evidence on the record

[80] Exhibit 43, Undertaking p.618-619

demonstrating that the forecast of system support service payments are understated. Further, it would clearly be inappropriate to deem a forecast for system support services payments as proposed by the TA.

Position of TransAlta

TransAlta submitted it did not forecast out of merit generation as it does not currently have a contract with the TA for support services which qualify for out of merit payment, and it does not believe that such a contract will be necessary in 1999 or 2000.

Respecting Operating Reserve, TransAlta submitted it typically provides only the automatic AGC portion of Operating Reserve from its thermal units equipped to provide the service. The arrangement with the TA enables the System Controller to choose any of TransAlta's units, except for Wabamun 1 and 2 which are not suitably equipped to provide AGC. To model the effect of the provision of AGC, the ACF of each of TransAlta's units, calculated in accordance with Decision U97065, Direction G-29, was reduced to the level shown in Table 6 of the Joint Utility Generation Modeling Assumption Package. TransAlta also submitted that it provides both the AGC and Spinning Reserve components of Operating Reserve from its hydro units. However, due to the short term storage and energy shaping capability of the hydro system, these services can be acquired by the TA without having to incur additional fuel and operating costs. Therefore, no forecast of fuel and operating costs was carried out for hydro.

TransAlta did not use modeling to forecast the variable component of system support services. Rather, TransAlta relied on a projection of historical data. In response to the EAL argument that TransAlta's forecast "significantly understates the system support services revenue" TransAlta noted that since EAL succeeded Gridco as TA, there has been an increase in the cost of providing system support services due to EAL's failure to optimize the acquisition of such service. TransAlta has presumed that with experience, EAL will recognize the need to improve its procurement of system support services, and that once this has occurred, revenue to TransAlta for system support services will revert to historical levels. Therefore, TransAlta submitted that it would not be appropriate to assume that an unrealistic level of system support services revenue will continue.

TransAlta indicated that its 1999 and 2000 system support services forecast was based on an average of the 1999 and 2000 pool price forecasts. TransAlta also indicated that the volume of energy lost to provide AGC for its thermal units (TransAlta's thermal units other than Sheerness only provide AGC) was held constant in 1999 and 2000. Therefore, the same variable cost of providing AGC of $3.3 million was forecast for 1999 and 2000.

In response to EAL's suggestion that a more rigorous, or more accurate, method would have been to carry out separate forecasts for 1999 and for 2000 to take into account the variation in the pool price, TransAlta testified that EAL's suggested method would only shift a little money from the year 2000 to the year 1999. However, TransAlta indicated the improvement would be

insignificant. TransAlta did admit though, that from a purely methodological perspective, EAL's suggested method would be more rigorous.

TransAlta testified that actual loss opportunity generation due to AGC in 1998 was as follows:

Sundance 2	5.8 GWh
Sundance 3	26.6 GWh
Sundance 4	63.8 GWh
Sundance 5	12.3 GWh
Sundance 6	27.1 GWh
Keephills 1	21.7 GWh
Keephills 2	27.9 GWh.
Sheerness 1	53.9 GWh
Sheerness 2	82.6 GWh
Total	**321.8 GWh**

Position of AE

AE submitted in EAL-APL-96 that variable revenue from ancillary services consist of three parts:

- out-of- merit due to units constrained up,
- lost opportunity revenue due to units constrained down,
- AGC revenue due to units constrained down.

The out of merit revenue is calculated for the hour when the Pool Price is less than UOP for the unit and the unit is committed and dispatched for system support using the following formula:

> Out of merit = MW dispatched for system support * (Pool Price - average variable cost at the dispatched MW for system support)

AE calculated the lost opportunity revenue by making simulations with and without the spinning reserve contributions from the units. The difference in the aggregate generation levels between the no spinning contribution and the spinning contribution scenarios give the lost opportunity MWh. The lost opportunity revenue was then calculated by using the following formula:

> Lost opportunity revenue = (lost opportunity MWh) * (pool receipts/unit generation - UOP)

The AGC revenue was calculated from the AGC MWh assumed in the modeling assumptions using the following formula:

> AGC Revenue = AGC MWh * (pool receipts/unit generation - UOP)

AE also submitted[81] the assumed generation lost due to units providing AGC. A flat 9.6 GWh were assumed for each of TransAlta's thermal units (excluding Wabamun units 1 and 2). Sheerness 1 and 2 lost generation due to AGC was assumed to be 142 GWh and 128 GWh respectively. Therefore, total lost generation due to AGC was assumed to be 336 GWh in 1999 and in 2000.

Position of the Intervenors

Position of EAL

EAL submitted it had two main concerns with respect to the system support services revenue forecast of the Utilities:

- the uncertainty of forecasting system support services revenue at a time of significant pool price volatility and regulatory change and
- the understatement of the total revenue from system support services.

EAL submitted that, whether or not a system support services revenue deferral account is implemented for TransAlta and EPGI, an upward adjustment in the forecast variable revenue from system support services is required for the following reasons:

- In the absence of a deferral account for system support services revenue, the upward adjustment is necessary to prevent substantial over recovery and unwarranted benefit to the shareholders of these two Utilities at the expense of EAL's customers.
- If a deferral account is implemented, the adjustment is required to reduce the balance in the account and the risk of rate shock.

EAL submitted that the TransAlta and EPGI forecast of revenue from system support services is materially understated. Actual receipts of system support services revenue in 1999/2000 will substantially exceed forecast. Therefore, EAL submitted that a more realistic forecast of system support services revenue is required not only to prevent an unwarranted benefit to the Utilities, but also to set an appropriate revenue baseline for the proposed system support services deferral account. EAL also submitted that the uncertainty surrounding the forecast system support services revenue results from the inability of the modeling tools to accurately forecast these revenues. Furthermore, the tight supply situation in the province leads to forecasts of system support service revenues that are very sensitive to relatively small changes in the input assumptions.

EAL indicated that the variations in the system support services revenue forecasts are significant. TransAlta has forecast $3.3 million in payments for AGC from thermal units in 1999 and 2000.[82]

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[81] IPCAA-APL-95
[82] IPCAA.TAU-63 Revised

AE[83] indicated a forecast of $7.8 million in payments to TransAlta thermal units in 1999 for AGC. The evidence demonstrates that the Utilities arrive at very different results using similar input assumptions and modeling tools.

EAL submitted that variations among the forecasts of system support services revenues are related to both the diversity and inadequacy of the modeling methodologies adopted by the applicants. The extent of the difference and the unreasonable degree of uncertainty that results was demonstrated in the following AE testimony:

> Alberta Power's review of the tri-utility modelling methodology and result lead Alberta Power to believe that, although the assumptions used by the three utilities for existing generating units are generally consistent, the treatment of ancillary services (must run, lost opportunity, etc.) and hydro dispatch are significantly different. Although minor variations are to be expected in such a complex and sensitive modelling process, the variations that occurred in the forecasts that the three utilities were preparing exceeded the range where group consensus could be achieved.[84]

EAL submitted that system support services costs are affected by changes in pool price and that continuing constraints on generation supply in 1999 and 2000 will contribute to significant pool price volatility. EAL, therefore, submitted that the swings in the cost of system support services can be extreme and quite erratic and since system support services are not a discretionary item, they must be purchased in each hour, regardless of the cost. Under these circumstances EAL stated that forecasting system support services revenue is a difficult, uncertain exercise that is subject to considerable error. Moreover, EAL submitted that the hydro modeling difficulties contribute to a lack of accuracy of the forecast of system support services revenue. Further, EAL stated that, in order to accurately forecast system support services revenues it is necessary to first accurately forecast hydro availability. Since a portion of the hydro system support services is provided to the TA at zero variable cost, variations in the level and timing of hydro generation can have a material affect on the forecast. The availability of hydro reserves determines the need to call upon the more costly thermal units. Overstating the availability of hydro system support services will understate the need for system support services from thermal units thereby understating the revenue received by the Utilities. Therefore, EAL believed that the amount of reserve available from hydro has been overstated resulting in an understatement of the reserve required from thermal units.

EAL requested that the Board direct the Utilities to produce a study of the historical hourly contribution to AGC, Spinning Reserves, and Operating Reserves from hydro and to use the results of this study to determine appropriate values for the maximum hourly contribution which hydro can contribute to operating reserve throughout the year.

[83] IPCAA.APL-95
[84] Exhibit 9, Section 3 Generation and Pool Price Forecast Modeling, p.G-8

EAL concluded that the large variation in forecasts, the large counterintuitive change in the overall level of forecast system support services payments and the lack of agreement on forecast methodology indicate that there is significant forecast uncertainty associated with system support services payments and therefore, system support services should be subject to deferral accounts.

EAL submitted that TransAlta and EPGI used different approaches forecasting system support services revenue. With respect to TransAlta's approach, EAL submitted the following:

- TransAlta did not determine the 1999 and 2000 system support services revenue through modeling. Instead, TransAlta used historical system support services revenue statistics. In the process, TransAlta conducted a "cherry picking" process and arrived at its conclusions based on selective historical data. TransAlta refused to recognize and account for changes in circumstances that were known at the time the forecast was completed. As a consequence, the TransAlta forecast significantly understates the system support services revenue that TransAlta will receive over the tariff period.

- TransAlta did not include the increase in system support services revenue after 1 June 1998. Instead, TransAlta treats the increase in payments as an anomaly making 1998 a "abnormal year."[85] In taking this approach, TransAlta ignored a change in policy of which it should have been aware before its application was filed. EAL has a policy to maintain reserve levels without regard to pool price, which has the effect of exposing the TA to high costs during periods of high pool price. This change in policy combined with a tight supply situation resulted in an increase in the system support services revenues paid by the TA to TransAlta after June 1998. EAL anticipated this increase to continue through the 1999 and 2000 test period. TransAlta's inference that the increase in system support services cost after 1 June 1998 is an anomaly is clearly wrong.

- TransAlta did not model the thermal AGC requirements on an hour-by-hour basis. Instead, TransAlta chose to model AGC as random derates. Since AGC is required in every hour of the year, it would have been more rigorous to model AGC requirements on an hour-by-hour basis. Unfortunately, under the approach taken by TransAlta, even if TransAlta were to get the actual volume of AGC requirements right, it would not have appropriate regard for the dispersion of the AGC requirement throughout the day. Without hourly modeling of the AGC output, TransAlta could not (and did not) accurately forecast AGC revenue.

- TransAlta made an assumption, which EAL believed was unwarranted, that AGC would be provided mainly at night and would therefore attract a price lower than the average.[86] By relying on an estimated price for AGC, TransAlta forecast AGC revenue of only $3.3

[85] Tr. p.3569, l.24-p.3570, l.2
[86] Tr. p.3562, l.25

million[87]. Average pool price should have been used by TransAlta when calculating thermal variable system support services revenue as AGC is required in all hours of the day. Had TransAlta used the annual average pool price, which EAL believed would have been appropriate in the circumstances, the forecast of AGC revenue would have been \$6.5 million,[88] approximately \$3 million higher than TransAlta's forecast. EAL also noted that the AE forecast AGC revenue is \$7.8 million for TransAlta in 1999[89], which is similar to the \$6.5 million in Exhibit 121 but not the \$3.3 million in the TransAlta application.

- TransAlta used an average pool price for the two-year tariff period. TransAlta agreed that a more rigorous approach would have been to do the calculations for 1999 and 2000 separately using the pool price forecast applicable to each year. Using observed AGC volumes for 1998 and the TransAlta forecast average pool price for each of 1999 and 2000 would result in thermal AGC revenues for TransAlta of \$12,311,193 and \$9,664,943. Therefore, EAL recommended that the Board adopt these values as a more appropriate forecast of variable AGC revenue for TransAlta for 1999 and 2000.

- TransAlta's forecast of under-run revenues for hydro is \$2 million. This forecast suffers from the same shortfall as the thermal forecast. TransAlta once again ignores the under-run payments received since June of 1998. Under-run is a lost opportunity cost service. Based on 1998 actuals and TransAlta's forecast pool price increase for 1999, a more appropriate forecast would be \$5.5 million for 1999. Using the same approach for 2000, the amount would be \$5.3 million.

With respect to EPGI, EAL submitted the following:

- EPGI followed a more appropriate route of attempting to model system support services revenue. However, EAL believed the EPGI forecast of thermal ancillary system support services revenue to be too low. EAL believed that all Utilities had overestimated the amount of reserves that can be procured from the hydro system. This has the effect of underestimating the reserves that will be procured from EPGI thermal plants and, consequently, understating the revenues to be received by EPGI for providing those services.

- System support services revenue to EPGI has increased steadily as the average Pool Price increased. In 1997, variable payments to EPGI for system support services were \$6.2 million. A re-forecast of variable 1998 payments to EPGI for system support services at the end of October 1998 was \$13.6 million. However, in contrast to the trend of steadily rising system support services payments with increasing average pool prices, EPGI has

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[87] Tr. p.3561
[88] Exhibit 121
[89] Tr. p.3567, l.10

forecast system support services revenue to be $11.9 million in 1999. This forecast occurs in a period when EPGI forecast the average Pool Price to be $37.60 MWh, which is $4.60 higher than 1998. In 2000, pool prices are forecast to return to $29.5 MWh and system support services revenue to EPGI is forecast to be $9.3 million.

- In the absence of deferral account treatment for system support services revenue, EPGI should be required to re-forecast the system support services revenue in a manner that properly accounts for availability of reserves from hydro units. EAL believed that such a forecast would result in system support services variable revenue to EPGI in 1999 at least equal to the October 1998 re-forecast amount of $13.6 million. However, for purposes of establishing a baseline for a deferral account, a re-forecast is not required. EAL recommended that it would be reasonable and more practical in the circumstances to set the baseline for 1998 at the re-forecast level of $13.6 million. A baseline of this amount would have due regard to the impact of increased Pool Price in 1999 and would be sufficiently accurate to minimize the balance in the deferral account. For 2000, EAL recommended that the EPGI variable system support services revenue be set at $11.7 million,[90] the amount recorded in 1998 which was the environment most similar to that expected for 2000 in terms of average pool price.

Position of ENMAX

ENMAX submitted that EPGI agreed that forecasting system support revenues is uncertain and that PROSYM and ENPRO result in different forecasts of such revenues. ENMAX submitted that a variability of $2 million (i.e., $13.6 million October 1998 reforecast minus $11.7 million actual) on a base of $13.6 million over a two month period clearly shows forecast volatility.

The evidence indicated that TransAlta had earned actual variable hydro revenues of $4.5 million in the six month period June-December 1998. In its 1999/2000 GTA forecast TransAlta predicts it will earn $2 million for the entire year. TransAlta confirmed that its forecast of variable ancillary service revenue was well below actuals and that the forecast was not the result of a modeling run but rather "trending" of past results. It would appear that there is significant volatility associated with forecasting ancillary services revenues and costs.

Board Findings

The Board is concerned that the system support services aspect of generation system modeling is prone to significant variations between forecast and actual results during this period of pool price volatility. However, the Board considers that with suitable input parameters and appropriate modeling techniques, it is possible to determine a reasonable baseline forecast of the annual system support (or ancillary) services revenues by generating unit and GENCO for the purposes of establishing an ancillary services deferral account. The Board will address the type of deferral account in the GENCO Deferral Accounts section, Part 1–General, Section 3(a)(4).

[90] Exhibit 8, Rebuttal of EPGI, p.5, Table 1

3. GENCO/TRANSCO/DISCO
(a) Generation

The Board earlier in this section found that PROSYM provides a more accurate forecast of hydro dispatch. The Board notes the evidence that the forecast of ancillary service revenues is significantly influenced by the hydro dispatch. Accordingly, the Board considers that PROSYM should be used to determine the forecast of ancillary service revenues. The Board, therefore, directs EPGI, in its refiling, to re-run PROSYM using all the parameters and techniques prescribed in this Decision and the following directions to obtain an appropriate ancillary service baseline forecast:

- EPGI should run PROSYM to forecast ancillary service revenue, i.e., variable payments for constrained on generation for transmission system support (or out of merit), variable payments for spinning reserve and variable payments for AGC.
- EPGI should maintain its assumption respecting the amount of spinning reserve available from hydro units, as EAL did not substantiate its submission that there is less spinning reserve available from hydro.
- EPGI should run PROSYM seven times when forecasting ancillary service revenues. Each run should consist of two cases, one with and one without unit constraints for ancillary services, but the same pattern of outages should be maintained. The difference between these two cases yields the ancillary service revenue for one run. This process shall be repeated seven times and the results averaged. EPGI should use the ACFs that include operation on AGC in the case with units constrained for ancillary services. However, the ACFs should not include operation on AGC in the case without unit constraints for ancillary services. EPGI should conduct separate simulations for the years 1999 and 2000.

The Board recognizes that the above method would yield each unit's forecast of lost generation due to the provision of spinning reserve and AGC combined together. This would be the case for the Sheerness units, as they provide both spinning reserve and AGC. The Board, however, is satisfied that the directed method would produce accurate revenues as the formulas to calculate them are identical. In both cases the lost energy, whether due to providing spinning reserve or due to providing AGC, is multiplied by the same expression: (pool receipts/unit generation - UOP).

The Board directs TransAlta to incorporate the results for ancillary services from EPGI's PROSYM runs in its refiling. The Board expects that the GENCOs will co-operate on information sharing as required to fulfill the Board's directions on these matters.

It is the Board's understanding that PROSYM does not have the capability of modeling hydro ancillary services.[91] Accordingly, the above modeling runs will not provide a forecast of hydro ancillary services.

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[91] Exhibit 179, Tr. p.4708

3. GENCO/TRANSCO/DISCO
(a) Generation

Therefore, with respect to TransAlta's forecast of under-run revenues for hydro of $2 million, the Board concurs with EAL's submission that these revenues appear to be understated, as 1998 actual revenues for hydro are under-run are significantly larger. The Board therefore accepts EAL's position that a more reasonable forecast would be $5.5 million for 1999 and $5.3 million for 2000. The Board further notes that, even though EAL's forecast figures were not tested, the Board's decision to establish a 100% system support services deferral account to capture differences between forecast and actuals, should alleviate any concerns that interested parties may have. Accordingly, the Board directs TransAlta, in its refiling, to use a forecast of $5.5 million for 1999 and $5.3 million for 2000 for hydro ancillary services.

(F) New Non-Regulated Generation

(i) Non-Utility Generation

The Utilities agreed respecting the timing, size, and characteristics of new "unregulated" non-utility generating units that, in their opinion, would be available in 1999 and 2000. The Utilities then used these generating units as an input into their energy simulation models to produce their 1999 and 2000 forecasts. The table below shows these new non-utility unregulated units, their output, and the expected in-service dates assumed by the Utilities. For those units with an uncertain in-service date, the Utilities assigned a less-than-100% probability and derated the output of those units according to the assigned probability.

Unit Name	In-Service Date	1998 Output (MW)	1999 Output (MW)	2000 Output (MW)	Probability
CUPIL Grande Prairie	Nov-98	40			100%
CUPIL Amoco	Nov-98	84			100%
CUPIL Rainbow Lake	Jan-99		40		100%
CUPIL NOVA - Joffre	May-00			300	100%
TEM Fort Nelson	Jan-99		25		100%
TEM Sundance	Jul-99		210		50%
TEM Sundance	Jul-00			120	50%
TEM Dow Ft Sask	Dec-99		40		100%
ALC Shell Scotford	Jul-00			49	100%
TOTAL		124	315	469	

Reference: Table 20 of the Joint Utility Generation Modeling Assumption Package

Only the generation net of on-site load was modeled since the on-site load was also excluded from the load forecast.

3. GENCO/TRANSCO/DISCO
(a) Generation

Position of the Utilities

In their Applications, the Utilities indicated that the forecast of new non-utility unregulated units was based on projects which had either received regulatory approval, which had regulatory approval pending or for which construction had already commenced. In one case, there was uncertainty as to whether a project would actually proceed. To reflect this uncertainty, a 50% probability was assigned to the project. The probability factor was applied to the forecast maximum continuous rating (MCR), which reduced the expected generation accordingly. The performance factors, heat rates, and fuel prices used in the models were estimated based upon typical characteristics.[92]

TransAlta testified that the forecast of new non-utility unregulated generation was prepared in October 1998 and reflected the Utilities best information at that time. TransAlta advised that the TransAlta Energy Marketing Corporation (TEM) Sundance project was not going to materialize, but indicated that an unforeseen new plant at Suncor made up for the difference. TransAlta testified that overall, it was comfortable with its forecast of non-utility unregulated generation and it did not propose to update it, as the differences would not have a significant effect on the generation forecast.

EPGI submitted the following updated list of new non-utility unregulated units:

Unit Name	In-Service Date	1998 Output (MW)	1999 Output (MW)	2000 Output (MW)
API	Jul-98	3		
Drayton Valley Power	Sep-98	17		
Grande Prairie	Nov-98	40		
Amoco	Nov-98	84		
Rainbow Lake	Jan-99		40	
Fort Nelson	Jan-99		25	
Dow Ft Sask	Dec-99		40	
Oldman Dam	Jan-00			8
Taylor Chute	Apr-00			12.5
NOVA - Joffre	May-00			300
Scotford	Jul-00			49
TOTAL		144	105	369.5

Source: EPGI updated list of non-utility generators (Exhibit 57)

[92]Table 20 of the Joint Utility Generation Modeling Assumption Package shows a more detailed list of unregulated unit characteristics.

3. GENCO/TRANSCO/DISCO
(a) Generation

Positions of the Intervenors

Intervenors did not submit evidence respecting the Utilities' forecast of new non-utility unregulated generation.

Board Findings

The Board considers that with suitable input parameters and appropriate modeling techniques, it is possible to determine a reasonable baseline forecast of the annual surplus/shortfall dollars by generating unit and GENCO for the purposes of fixing reservation prices for the test years. Further, the Board notes that the Utilities are forecasting annual average pool prices of $38/MWh in 1999 and $30/MWh in 2000. The Board also notes that, although the provincial load is forecast to increase by 0.5% from 1999 to 2000, the decrease in pool price is mainly due to the addition of these new sources of generation. Therefore, the Board considers that the latest available information regarding new sources of generation should be used in arriving at a reasonable baseline forecast, as this information has a significant affect on pool prices and the resulting surplus/shortfall. The Board considers that this finding does not violate the forward test year concept since the Board in the GENCO Deferral Account Section later in this Decision has found that pool price risk should be excluded from the forecast test year revenue requirement and handled by way of a deferral account.

The Board notes that the approved Suncor plant near Fort McMurray was not included in EPGI's updated list.[93] Suncor's original plan was to have two 115 MW gas-turbines operating in September of 1999 and to add one 60-MW steam turbine by February 2000 and another 70-MW steam turbine by October 2000. The full load increase of Suncor's expansion would not be coming on-stream until 2001. However, recent information available to the Board regarding the status of the Suncor Plant indicates that the first gas-turbine unit will likely start commercial operation in December 1999 and the second gas-turbine unit in January 2000. The Board also expects that the Joffre Plant would be available by 1 April 2000. Therefore, the Board considers the inclusion of these units in the Utilities' 1999 and 2000 forecasts to be appropriate.

The Board further notes that there are other plants that have received recent Board approval. Accordingly, the Board directs EPGI and TransAlta, in their refilings, to include the following new generating units in their 1999 and 2000 forecasts:

[93] Exhibit 57

3. GENCO/TRANSCO/DISCO
(a) Generation

Power Plant Name (Location) Company Name per EUB Approval	In-Service Date	1998 Output (MW)	1999 Output (MW)	2000 Output (MW)
Drayton Valley Power (Dapp Area) DVP Purchase Corp., Westlock Power	1-Sep-98	17		
Grande Prairie Plant (Poplar Hill) CU Power Canada Limited	1-Nov-98	40		
Primrose Plant CU Power Canada Limited and Amoco Canada Resources Ltd.	1-Nov-98	84		
Rainbow Lake Plant CU Power Canada Limited	1-Jan-99		40	
Fort Nelson Plant (British Columbia) No EUB Approval	1-Jan-99		40	
Dow Fort Saskatchewan Plant TransAlta Energy Corporation and Air Liquide Canada Inc.	1-Dec-99		40	
Taylor Chute Plant (Magrath Area) Canadian Hydro Developers Inc.	1-Jun-00			12.5
Scotford Plant (Fort Saskatchewan) Air Liquide Canada Inc.	1-Jul-00			49
Joffre Plant NOVA Chemicals Limited	1-Apr 00			461
Suncor Plant Unit 1 (Fort McMurray) TransAlta Energy Inc.	1-Dec-99		115	
Suncor Plant Unit 2 (Fort McMurray) TransAlta Energy Inc.	1-Jan-00			115
Suncor Plant Unit 3 (Fort McMurray) TransAlta Energy Inc.	1-Feb-00			60
Suncor Plant Unit 4 (Fort McMurray) TransAlta Energy Inc.	1-Oct-00			70
Plant in M.D. of Pincher Creek Canadian Gas and Electric Ltd.	1-Oct-99		6	
Gold Creek Plant (Grande Prairie) NOVA Pipelines Venture	1-Jun-99		6.5	
Plant on East Bank of Castle River Vision Quest Windelectric Inc.	1-Dec-00			6.6
Flare/Solution Gas Units Renaissance Energy Ltd.	1-Oct-99		2	
TOTAL		**141**	**249.5**	**774.1**

The Board notes that the above list considers the full output of the Suncor units and the Joffre units. The Board directs EPGI and TransAlta, in their refilings, to either include in their load forecast the full load of these industrial complexes or to decrease the outputs of the units such that only the net energy supplied to the pool is included in the modeling.

The Board also notes that Exhibit 57 shows the Oldman Hydro Plant available in January 2000. However, the application filed with the Board shows a commissioning date in 2001. Also, information available from the Power Pool indicates the net capacity of the Fort Nelson plant is about 40 MW.

The Taylor Chute plant would generate about 40 GWh during the irrigation season (April to October). There would be no generation form November to March when the irrigation canals are shut down. Therefore, the Board directs EPGI and TransAlta, in their refilings, to use the following monthly MW output for the Taylor Chute plant to account for water availability:

Month	Output (MW)
January	0
February	0
March	0
April	2.2
May	9
June	12
July	12.5
August	11.2
September	7.1
October	3
November	0
December	0

The Vision Quest plant is wind-powered. Therefore, the Board directs EPGI and TransAlta, in their refilings, to use a FMOR of 50% to account for wind availability.

Flare/Solution Gas Units are a collection of almost 30 small units. Therefore, the availability of the combined 2 MW of capacity should be very high.

(ii) Small Power Producers

Small Power Producers (SPPs) are those generating units that have been approved under the Small Power Research and Development Program. As SPP units are typically of small size, the Utilities aggregated the capacities of all SPP units and modeled them as a single unit[94]. The recently commissioned Drayton Valley Power SPP was also included in the Utilities SPP model.

Intervenors did not submit evidence respecting the Utilities modeling of SPP units. Some Intervenors raised the issue of TransAlta payments to SPPs, however, this issue is addressed in Part 4–TAU, Section 2(e).

[94] Table 12 of the Joint Utility Generation Modeling Assumption Package shows the output assumed for SPPs on a monthly basis.

Board Findings

The Board considers the treatment of SPP units to be appropriate and notes that it is also consistent with the way SPP units were modeled in the 1996 GRA proceeding. The Board therefore agrees with the SPP modeling used by the Utilities in their 1999 and 2000 generation forecasts.

(G) Exports

Position of the Utilities

The Utilities agreed to the set of assumptions used to forecast exports in 1999 and 2000.[95] Export volumes submitted by AE were 197 GWh and 348 GWh in 1999 and 2000 respectively.

The Utilities submitted that the starting point for forecasting exports was the forecast market price in the Pacific Northwest at Mid-Columbia. Future prices at Mid-Columbia for 1999 and 2000 were first converted to Canadian dollars. The price was then reduced to recognize transmission costs from Alberta to the Pacific Northwest. Finally, the price was reduced another $3/MWh to recognize exporters' expected profit margin. The Utilities also indicated that the forecast export bids were high enough to result in exports occurring even when gas-fired units are setting the pool price in Alberta. However, they recognized that exporters will often limit the amount of exports to avoid the dispatch of gas-fired units. Therefore, in order to reflect this strategy, the amount of exports at high bid prices was limited to 150 MW. The remaining 810 MW of export capacity was priced below H.R. Milner but above the UOP of the remaining coal-fired units in the province. EPGI clarified that the highest export price for 1999 is $25.60 per MWh and the lowest UOP for a gas-fired unit is $26.81/MWh. All new gas generation is forecast to produce energy at low enough prices to allow for some exports from gas-fired generation during some months.

The Utilities further explained that the exports were modeled such that up to 960 MW of exports would be forecast as long as the pool price remained below $10/MWh. This level of export is consistent with full utilization of the ties when coal fired energy is available. Exports of up to 150 MW would be forecast to come from higher cost resources as long as the pool price remained below the Mid-Columbia price, adjusted for transmission charges to the Alberta-B.C. border.

The Utilities did not forecast any exports to Saskatchewan or to the City of Medicine Hat. They assumed that any forecast exports would be immaterial given the tight supply / demand balance on the AIS and the fact that there is sufficient export capacity to B.C. to account for any exports that may occur. It was assumed that export volumes to Saskatchewan would be small, and that the export assumptions applied to the interconnection with B.C. would capture the effects of exports to Saskatchewan. The export modeling was done based on the external market prices and

[95] Table 4 of the Joint Utility Generation Modeling Assumption Package shows export assumptions.

the AIS capacity to export. The tie line capacity for export from Alberta was assumed to be 960 MW. This amount is much greater than the surplus generation available from the base loaded coal units after meeting the AIS load. Since the export from the base loaded units was limited by the surplus available in Alberta rather than the capacity of the tie line, the modeling of any export to Saskatchewan from these base loaded units would have made little difference.

In regard to EPI's application to the National Energy Board for approval to export up to 1,000 GWh of short-term firm power and up to 3,000 GWh of total energy each year through 1999, EPGI submitted that no energy has been exported by EPI/EPGI pursuant to its license and that no revenue has been realized, since there was no export. Furthermore, EPGI submitted it did not forecast any exports in 1999 and 2000 pursuant to this Permit.

AE further explained that the first step of forecasting export sales was the forecast of Pool Price in Alberta over the test period. Once a forecast of Pool Price was available, a forecast of the price responsiveness of the export market was required. Further, AE submitted that the price responsiveness of the export market depends on weather, performance of other party' s generation, and expected load developments in the export market. This price responsiveness is then modeled in the Pool Price forecast in an iterative manner until the impact of exports on the Pool price balances the price responsiveness of the export market. AE, therefore submitted that, because of the difficulty in developing a robust pool price forecast, it concluded that any export forecasts would be equally or more speculative than the surplus/shortfall forecast.

Position of the Intervenors

Intervenors did not submit specific evidence regarding the way the Utilities modeled exports in their forecast. Intervenors mentioned the modeling of exports in the broader context of forecast uncertainties, such as: forecast load, gas prices, imports and export prices, availability of hydro units for purposes of system support, etc.

Board Findings

The Board has reviewed the Utilities' modeling of exports and considers the assumptions and modeling process to be appropriate. The Board notes that issues regarding forecast uncertainty around export prices will be addressed by the establishment of pool price deferral accounts in the GENCO Deferral Accounts, Part 1–General, Section 3(a)(4) of this Decision.

(H) Imports

Position of the Utilities

The Utilities agreed on the input assumptions used to model imports from neighbouring power systems. Imports were modeled as generating units that are available at different levels of output

and at different levels of availability. The Utilities also agreed on the price at which these imports would offer energy into the Pool.[96]

The Utilities modeled imports from B.C. as a generating unit with availability segregated into three blocks:

- the first 200 MW at 89.9% availability,
- the next 165 MW at 75.4% availability, and
- the last 200 MW at 40.6% availability

for a total of 565 MW of capacity available from B.C..

The Utilities submitted that, for the purposes of forecasting imports over the B.C. Tie in 1999 and 2000, they started from the perspective of an importer purchasing energy in B.C. Since, the importer has the option of selling the energy to the U.S., market prices in the Pacific Northwest were assumed to set the floor for import offers into Alberta. Therefore, the Utilities used futures prices at Mid-Columbia, adjusted for differences in the cost of transmitting the energy to Alberta as opposed to the Pacific Northwest, as a starting point for determining import offers over the B.C. Tie. Given the large hydro storage capability in B.C., it was assumed that potential importers would base their import offers on the highest price projected over a two-month period.

Therefore, the capacity from B.C. was assumed to be offered into the pool at the following prices:

- the first 365 MW at prices that vary month by month in the $19.6 to $42 per MWh range, and
- the last 200 MW at prices that vary month by month in the $22.5 to $45 per MWh range.

The Utilities priced the last 200 MW block higher than the first 365 MW to account for the charges associated with the Remedial Action Scheme (RAS).

The Utilities also agreed that the full capacity of the B.C. imports were available most of the time but at higher prices. Therefore, they assumed that the full 565 MW was available 99.7% of the time at a price of $250 per MWh during the periods when the less-expensive blocks of capacity from B.C. were unavailable. However, TransAlta submitted it was unable to model the $250-per-MW-block in ENPRO but further submitted that its effect was not significant as the $250-per-MW-block was "dispatched" very few hours each year.

EPGI submitted that the limit on the B.C.-tie has been increased since EPGI completed its 1999/2000 forecast. The maximum capacity on the tie has increased to 640 MW when the

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[96] Tables 4 and 5 of the Joint Utility Generation Modeling Assumption Package shows the input assumptions.

Alberta load exceeds 6500 MW and to 765 MW when the Alberta load exceeds 7000 MW, assuming there are sufficient customers on the RAS to ensure system integrity. The capacity of the B.C.-tie would also be increased by 200 MW, up to a maximum of 765 MW when a Firm Load Alert is issued by the Power Pool regardless of the total AIS load. In this regard TransAlta testified that if it had modeled the extra 200 megawatts, with its various constraints, it would not have materially change its overall forecast.

The Utilities submitted that they modeled imports from SaskPower based on historical data, as there are no market prices in Saskatchewan. Based on a review of actual imports since 1996, the SaskPower tie was broken into two blocks. The first block of 85 MW is forecast to be available at a price of $55/MWh with an availability factor of 71%. The second block of 50 MW is expected to only be available at prices of $200/MWh or greater with an availability of 63%.

The Utilities modeled imports from the City of Medicine Hat (CMH) also as a generating unit that can provide 20 MW with 100% availability, 50 MW with 98% availability and the full 80 MW at a 30% availability. The Utilities assumed that CMH would only use the full interconnection capacity during system emergencies given the significant risk placed on CMH's electric system if the CMH Tie were to trip. The Utilities assumed that CMH would offer up to 50 MW at a price equal to the gas-price for Clover Bar. The full 80 MW was assumed to be offered at $999 per MWh.

TransAlta testified that the import levels from CMH did not reflect the additional 38 megawatt plant that will sell power to CMH which was the subject of an application to the Board by TransCanada Energy. TransAlta explained that the import levels are tied more to the interconnection capability than to CMH generation. TransAlta indicated that the safe operating limit of imports from CMH are about 80 MW. When the import level is around 80 megawatts and considering that the load is just over 120 megawatts, a loss of the tie would disrupt the CMH system and send it into perhaps an unstable operating condition.

Position of the Intervenors

IPCAA conducted significant cross-examination of the Utilities' witnesses respecting the modeling of imports. However, Intervenors did not submit or propose any alternative ways of modeling imports or propose changes to the Utilities' assumptions. Intervenors did refer to modeling of imports as one of the many factors that made forecasting unreliable and within the context of their support for the establishment of deferral accounts.

Board Findings

The Board considers that the latest available information regarding sources of supply, including imports, should be used in arriving at a reasonable baseline forecast, as this information has a significant affect on pool prices and the resulting surplus/shortfall. The Board considers the use of some actual data for this import parameter to be a reasonable way of mitigating the variance between forecast and actual pool price with respect to a parameter that is outside the control of the Utilities. The Board considers that this finding does not violate the forward test year concept

since the Board in the GENCO Deferral Accounts, Part 1–General, Section 3(a)(4) of this Decision has found that pool price risk should be excluded from the forecast test year revenue requirement and handled by way of a deferral account. Therefore, the Board has used actual data for 1999, published by the Alberta Power Pool, to test the reasonableness of the Utilities' modeling of imports from neighboring power systems.

The Board notes that the Utilities are forecasting about 60 GWh of electric energy from SaskPower in 1999. However, actual imports from SaskPower have already exceeded 130 GWh in the first 7 months of 1999. A preliminary analysis of 1999 import levels from SaskPower indicate a wide range of imports, up to 120 MW, occurring at pool prices ranging between $24 and $40 per MWh. The Utilities, however, assumed that imports from SaskPower would not occur at prices less than $55 per MWh. The Board also notes that there are a significant number of hours in which the import level from SaskPower is within 140 to 155 MW and at pool prices averaging $117 per MWh. The Utilities, however, assumed the maximum import level of 135 MW and at pool prices of $200 per MWh.

Therefore, the Board directs EPGI and TransAlta, in their refiling of modeling re-runs, to change the assumptions respecting the way the SaskPower Tie was modeled such that the forecast of imports from SaskPower will exceed 200 GWh in 1999. The revised 1999 assumptions should also be used for the year 2000.

Regarding imports from CMH, TransAlta is forecasting 202 GWh and EPGI is forecasting 355 GWh of electric energy from CMH in 1999. Actual imports from CMH in the first 7 months of 1999 have reached 130 GWh, which suggests that the Utilities forecast is reasonable.

Similarly, TransAlta and EPGI are forecasting 1,931 GWh and 1,654 GWh of electric energy from B.C. Hydro for 1999. Actual imports from B.C. Hydro in the first seven months of 1999 have reached 1,185 GWh, which also suggest that the Utilities' forecast of imports from B.C. is reasonable. However, the Board notes that the capacity of the B.C. tie has been recently increased by 200 MW and the Utilities have not captured this increase in their forecast. Therefore, the Board directs TransAlta and EPGI, in their refilings, to include a third 200-MW block of capacity, for a total of 765 MW, available for B.C. Hydro imports to be offered at $250 per MWh.

(I) Unit Gas Prices

This section addresses issues respecting the forecast gas prices used as inputs to the models that the Utilities used to prepare their 1999 and 2000 generation forecasts.

Position of the Utilities

The Utilities agreed on a forecast of natural gas prices for 1999 and 2000. These prices were used in the Utilities' generation models to forecast energy production, fuel costs and start-up costs. The utilities explained the forecast was based on the NYMEX futures price with an

adjustment for the basis differential back to AECO 'C' in Alberta. EPGI further explained that the forecast gas price at AECO 'C' was based on the average of the bid and ask prices for monthly forward gas contracts from January 1999 through December 2000. The forward strip (shown in the table below) was provided by Engage Energy, which developed the strip based on market information available as of 9:00 a.m. on 20 August 1998.

	Forward Strip for AECO 'C' 1999 - $/GJ	Forward Strip for AECO 'C' 2000 - $/GJ
January	2.92	2.84
February	2.81	2.70
March	2.65	2.53
April	2.44	2.34
May	2.40	2.30
June	2.40	2.30
July	2.40	2.31
August	2.40	2.33
September	2.40	2.34
October	2.44	2.39
November	2.60	2.61
December	2.79	2.81

The forecast AECO 'C' prices were further adjusted to reflect prices at the burner tip as follows:

Thermal Units	Burner Tip Adjustment
Rainbow Units	No adjustment
Sturgeon Units	$0.050 per GJ
Clover Bar and Rossdale Units	$0.073 per GJ

The forecast gas prices for startup fuel at the coal-fired units were based on Northwestern Utilities Limited's Rate 6. Table 14 of the Joint Utility Generation Modeling Assumption Package shows the natural gas prices for 1999 and 2000 for each thermal unit and on a monthly basis.

Position of the Intervenors

EAL cited natural gas prices, together with load forecast uncertainty, import and export prices, difficulties with forecasting the availability of hydro units for purposes of system support, planned turnaround schedules that change several times a year, as the major sources of forecast uncertainty. The uncertainty was detailed to support the establishment of deferral accounts.

3. GENCO/TRANSCO/DISCO
(a) Generation

IPCAA submitted that the outputs of the coal units, which are subject to random availability, determines the need for gas units. If a gas-unit is on the margin, the pool price is a function of the assumed gas price. Therefore, the forecast of pool price is very sensitive to the assumed cost of natural gas because gas units are on the margin, and therefore setting pool price, for a large number of hours during the year.

IPCAA also submitted that the utilities used a common forecast of gas prices and that they assumed that the gas price for each month would be the same in all days of that month. However, IPCAA submitted that the actual gas price varies daily and that even if the actual average monthly price turns out to be the same as forecast, pool price will change from day to day.

IPCAA submitted that the major uncertainties associated with producing a pool price forecast include:

- load uncertainties,
- the availability of existing units,
- the addition of new generation,
- natural gas price,
- the price and availability of imports,
- the possibility that the pool price cap of $1000/MWh may be removed or increased, and
- the treatment of system support services by the Transmission Administrator.

IPCAA further indicated that pool-price-forecasting was made even more difficult by the need to forecast pool prices on an hourly basis. Therefore, IPCAA recommended the establishment of deferral accounts to mitigate the uncertainties associated with forecasting pool prices.

IPPSA/SPAA submitted that the price of supply for gas units is directly related to the cost of natural gas. Also, the price of Exports and Imports is linked to the cost of natural gas since natural gas units ultimately form the competitive baseline for power exports and imports to and from the U.S. Market. Further, pool price is set by gas units, Exports, and Imports for 7130 hours in 1999 and 7496 hours in 2000. Therefore, IPPSA/SPAA submitted that any percentage change in the cost of gas would translate into a similar percentage change in pool prices, and any change in pool price translates directly to a change in a generator's surplus/shortfall position. Therefore, IPPSA/SPAA concluded that the surplus/shortfall estimates are extremely sensitive to uncontrollable parameters such as gas price.

The FIRM Customers submitted that gas prices were one of the many factors affecting the volatility of pool prices.

Board Finding

Intervenors' evidence with respect to natural gas prices, was mainly confined to forecasting uncertainty and its effect on forecast pool price and resulting surplus/shortfall calculations. The

thrust behind this evidence was to support the Intervenors' request that the Board establish deferral accounts as a means to mitigate pool price and surplus/shortfall volatility.

The Board concurs with the Intervenors' position that gas-price volatility is one of the several reasons for forecast uncertainty and the resulting discrepancies between forecast pool prices and actual pool prices. Therefore, the Board is satisfied that issues regarding forecast uncertainty due to natural gas-prices will be addressed by the establishment of pool price deferral accounts later in this Decision.

(J) Unit Coal Prices

This section addresses the forecast coal prices from the perspective of the inputs to the models that the Utilities used to prepare their 1999 and 2000 generation forecasts. In particular, the method of incorporating coal costs into the UOPs used for modeling purposes is addressed below. However, specific issues regarding some assumptions used by EPGI and TransAlta, as well as TransAlta's coal amortization, are addressed in Part 3 and Part 4 of this Decision.

Position of the Utilities

The Utilities agreed on the following forecast of unit coal prices for 1999 and 2000. These prices were used in the Utilities' generation models to forecast energy production and variable fuel costs.

Plant	1996 Forecast Price ($/GJ)	1999 Forecast Price ($/GJ)	2000 Forecast Price ($/GJ)
Keephills	0.185	0.235	0.260
Sundance	0.196	0.248	0.273
Wabamun	0.197	0.222	0.279
H.R. Milner	0.430	0.490	0.530
Battle River	0.433	0.439	0.449
Sheerness	0.468	0.491	0.501
Genesee	0.217	0.225	0.239

AE submitted that in Decision U97065[97] the Board directed all Utilities to develop a common approach to assigning mining costs between fixed and variable components. Therefore, as a response to this direction, a common approach was developed by AE, EPGI and TransAlta according to the following.

AE explained that generation coal costs at the H.R. Milner station had little relationship to the coal supplier's mining costs and therefore, the approach did not apply to it. Also, AE indicated that for EPGI's and TransAlta's units (other than TransAlta's share of Sheerness), the coal costs

[97] Section 14 (a) (1), p.248

were a function of the mining costs which are incurred by the mining contractors. The fixed and variable portions of these mining costs can be readily determined. Expressed in dollars per GJ, the variable portion is constant over the entire possible range of production. Therefore, these calculations were straightforward. However, generation coal costs at Battle River and Sheerness were governed by the prices in the coal contracts. Because of the complex provisions of these contracts, the fixed portion of the coal costs cannot be isolated explicitly, as this figure depends on several variables. Nevertheless, the variable coal costs can be readily determined over a given range of production during a calendar year. AE submitted that, although the variable cost, expressed in dollars per GJ, may not be constant over the range, an average variable cost can be determined over the range using the following formula:

Average variable cost [$/GJ] = (Coal cost2 - Coal cost1,)/(Coal energy2 - Coal energy1)

Where:

- **Coal cost2** is the cost of coal at the highest level of production that can be reasonably anticipated,
- **Coal cost1** is the cost of coal at the lowest level of production that can be reasonably anticipated,
- **Coal energy2** is the amount of coal energy required at the highest level of production that can be reasonably anticipated, and
- **Coal energy1** is the amount of coal energy required at the lowest level of production that can be reasonably anticipated

AE explained that this average variable cost (per GJ) is multiplied by the forecast coal energy required (GJ) to determine the variable component of the coal cost ($). The remaining portion is the fixed component. EPGI submitted that, in response to the above Board direction, the Utilities developed a common approach to assigning mining costs between fixed and variable components and reflected that cost-breakdown in their UOPs.

Board Findings

The Board has reviewed the method of incorporating coal costs into the UOPs used for modeling purposes and is satisfied that a common approach is being used by the Utilities to assign mining costs between fixed and variable. Accordingly, the Board approves the method of incorporating coal costs into the UOPs used for modeling purposes.

(2) Surplus/Shortfall

This section of the Decision is primarily a description of the main factors and parameters affecting the surplus/shortfall calculation. It also contains a summary of the Utilities' modeling results respecting some of these factors and parameters.

3. GENCO/TRANSCO/DISCO
(a) Generation

System support services receipts are sometimes included in the surplus/shortfall amounts. For the purposes of this Decision the Board will not include system support service receipts in the surplus/shortfall amounts. The Board has included a description of the system support services in the next section of this Decision. The Board will deal with system support service receipts as a separate component used in the determination of generating unit reservation prices.

Accordingly, in the case of a forecast surplus, the generation unit reservation price is to be determined by subtracting the surplus and system support service receipts from the fixed cost of each generating unit. In the case of a forecast shortfall, the reservation price is to be determined by adding the shortfall and subtracting the system support service receipts from the fixed cost of each generating unit.

The hourly surplus/shortfall amount for each generator is calculated as:

- Sales at the pool price
- Less UOV refunds
- Less variable O&M and fuel costs

The UOV refund in the above formula represents the legislated hedge designed to protect the DISCOs against increasing pool prices. The UOV Refund is calculated, for each hour, as the difference between the hourly pool price and the UOP multiplied by the UOA.

A surplus would exist, for a given generator in a particular hour, if the sales at the pool price exceed the UOV refund plus the generator's variable O&M and fuel costs. This situation normally occurs when the output of the generator is above the legislated UOA for that hour.

Conversely, a shortfall would exist if the sales at the pool price are not sufficiently high enough to offset the UOV refund plus the generator's variable O&M and fuel costs. A shortfall would exist in certain situations when a generator is running but its output is below its UOA. However, the most typical situation for a shortfall occurs when the generator is on outage. In this case, the generator is not selling to the pool and is not incurring variable O&M and fuel, but it has to pay the UOV to the DISCO.

The annual surplus (or shortfall) for a generator is therefore the summation of the hourly surpluses (or shortfalls) calculated at each hour during the year. The annual surplus/shortfall for each GENCO is the sum of the annual surplus/shortfalls for each of the GENCO's generating units.

The main factors and parameters that can effect the surplus/shortfall calculation are as follows:

- Generation Volume
- Pool Price and Asymmetry Effect
- Pool Receipts, Obligation Value Refunds and Variable Costs

3. GENCO/TRANSCO/DISCO
(a) Generation

These surplus/shortfall factors are discussed in the following sub-sections. A discussion of the system support service receipts follows the discussion of the surplus/shortfall factors.

(A) Generation Volume

The Utilities used a five-year rolling average of forced outage rates in the modelling runs to forecast generation volumes. These forecast forced outage rates were higher than the actual forced outage rates experienced in 1998.

The Utilities noted that customers will benefit from the improved performance of the generating units due to updating the five-year rolling average from 1996.

The following table shows the generation volume results of the Utilities' modeling for 1999.

Forecast 1999 Generation Volume
Generation
(GWh)

AE GENCO	
Per AE-G	8,596
Per EPGI	8,709
Per TAU-G	8,773
Average	8,693
Variance from Ave	1%
EPGI Results	
Per AE-G	9,237
Per EPGI	9,344
Per TAU-G	8,979
Average	9,187
Variance from Ave	2%
TAU-G Results	
Per AE-G	29,812
Per EPGI	29,814
Per TAU-G	29,737
Average	29,788
Variance from Ave	<1%

Source: IPCAA Evidence, Volume II, Section 1, p.11

3. GENCO/TRANSCO/DISCO
(a) Generation

Board Findings

The Board notes that the variation in total forecast generation volume is not significant and that the determination of an accurate surplus/shortfall amount depends on the hourly level of generating unit output. The Board, in the "GENCO Deferral Accounts" section determined that forecast modeling parameters should be developed using actual performance data over the three-year period 1996-1998. The Board also determined that it would not be necessary to set up a deferral account with respect to forecast generation volume.

(B) Pool Price and Asymmetry Effects

The Utilities were unable to agree on a common pool price forecast as illustrated by the following table:

Average Pool Price Forecast
($/MWh)

Forecast By	1999	2000
AE-G	$39.04	$29.82
EPGI	$37.66	$29.48
TAU-G	$38.05	$30.80
High-Low	$1.38	$1.32

Source: IPCAA Evidence, Volume II, Section 1, p.8

It is illustrative to examine the averages for on-peak and off-peak periods as defined in the DISCO tariffs as set out in the following table:

1999 Pool Price Forecast
($/MWh)

	On-Peak	Off-Peak	Avg	Ratio On/Off	Difference On/Off
AE-G	$53.1	$30.1	$39.04	1.76	$23.0
EPGI	$51.1	$29.2	$37.66	1.75	$21.9
TAU-G	$50.1	$30.5	$38.05	1.64	$19.5
High-Low	$3.0	$1.3	$1.4		

Source: IPCAA Evidence, Volume II, Section 1, p.8

IPPCA noted that generator UOAs are not constant; they are shaped and are higher in on-peak periods than in off-peak periods. The potential to accumulate surplus energy is greater in off-

peak hours. Therefore the calculation of generator surplus/shortfall is not a linear relationship with average pool price. While TransAlta's average Pool Price forecast lies between AE's and EPGI's, the hourly Pool Price behavior is significantly different. TransAlta is forecasting a much smaller on/off peak differential than the other two applicants.

EPGI noted that actual pool prices have been substantially higher than the pool price forecast in the 1996 GTA Refiling. The net effect of higher pool prices on a Unit's net surplus/shortfall position depends on the Unit's availability. When the Unit is available, higher pool prices result in a higher surplus. On the other hand, when the Unit is unavailable, higher pool prices result in a higher shortfall. As availability increases, the benefit from higher pool prices in terms of the surplus exceeds the offsetting shortfalls.

EPGI set out a simple example to illustrate the above effect. Assume a 400 MW generating unit has a 340 MW UOA, an availability of 85%, and to simplify the discussion, no fuel costs. If the pool price increases $10/MWh, the surplus position of the unit would increase by $4.5 million [(400 MW–340 MW) x $10/MWh x 8,760 hours x 85%]. However, during periods when the unit is unavailable, the shortfall also increases by $4.5 million [340 MW x $10/MWh x 8760 hours x15%]. In this simple example, the net surplus/shortfall position of the generating unit is actually unaffected by the increase in pool prices.

EPGI noted that a complicating factor in considering the impact of higher pool prices is what has sometimes been referred to as the "asymmetry effect." Given that the supply curve is upward sloping, pool prices on average are higher when a unit is unavailable than when it is available. Returning to the previous example, assume that the pool price still increases $10/MWh on average but the increase is $12.0/MWh during periods when the unit is unavailable and only $9.60/MWh when the unit is available. The increase in the Unit's surplus due to higher prices is only $4.3 million while the increased shortfall is $5.4 million. The Unit's net surplus/shortfall position actual worsens by $1.1 million.

EPGI calculated the impact of the asymmetry effect based on its modeling runs in the 1996 GTA Refiling. The average pool price in EPI's seven runs was $12.9/MWh. However, the forecast average pool price for Genesee output above its UOA was $11.6/MWh compared to $19.4/MWh when Genesee output was less than its UOA. The asymmetry of the pool prices increased Genesee's shortfall costs relative to the forecast surplus, which had a net effect of reducing the forecast net surplus/shortfall position for Genesee by $5 million.

EPGI then calculated the asymmetry effect based on the actual results in 1996. The average pool price for the surplus output from Genesee was $12.9/MWh while the average price during shortfalls was $13.2/MWh. The actual reduction in Genesee's net surplus/shortfall position in 1996 was $0.7 million.

IPCAA's position respecting asymmetry was outlined in evidence as follows:

The "asymmetry effect" is the loss that is claimed to occur because the per-kWh profit when a unit operates above UOA is less than the per-kWh loss (when a unit operates below UOA).

This asymmetry effect is a result of variations in the Pool Price. If the Pool Price were the same at all hours, a net *energy* surplus/shortfall of zero would translate into a net *dollar* surplus/shortfall of zero. The claim is that an outage of a major unit will drive up the Pool Price (thereby increasing the shortfall), while extra availability will not have as much of an effect in reducing the Pool Price. If this is true, even if the total surplus and shortfall kilowatt hours are exactly in balance, the surplus and shortfall dollars would not be There would be a net dollar shortfall. This was taken into account in setting the UOAs. The expectation was that units would have a net energy surplus, because the UOAs were set at a level about 5% below ANEC. (This was called the "financially sensible ANEC.") The calculated profits from these energy surpluses would be offset by the asymmetry effect, eventually resulting in a zero dollar surplus/shortfall.

In practice, this effect is smaller than claimed—and sometimes even negative. We saw an example of this in 1996. For 1996, the forecast was that the Genesee units would produce 458 GWh more than total UOA (forecast generation of 6,054 GWh versus UOA of 5,596 GWh). At a constant Pool Price, this would have produced a $4.7 million surplus (=458 GWh x ($13.07 Pool Price - $2.72 UOP)). However, the calculated result was a shortfall of $0.1 million. Thus, the asymmetry effect included in the modeling was a *negative* $4.8 million. The actual 1996 asymmetry effect was much smaller—only about negative $0.5 million.

One problem with the claimed asymmetry effect is that it looks at plants in isolation. If the outage of a large plant increases the Pool Price, that particular plant may experience an increased shortfall, but all other plants will experience bigger surpluses. Thus, the Genesee plant would benefit any time Keephills or Sheerness goes out of service. A second problem is that plant availability is treated as probabilistic. If a plant outage causes the Pool Price to increase unexpectedly, plant operators can defer a maintenance outage to some extent or reschedule a planned outage. Thus, availability is not a function of probability alone, but must take into account operator decisions.

This is another area where customers are at a significant disadvantage in evaluating the results. The utilities use proprietary models, so customers cannot examine the way in which this is modeled.[98]

[98] IPCAA Evidence, Volume II, Section 1, p.9-10

Board Findings

The Board notes that the variation in hourly pool prices and the asymmetry effect can have a material effect on the forecast surplus/shortfall. The Board also notes that load/resource balance uncertainty can have a significant effect on the forecast of pool prices as illustrated by the following table:

Sensitivity of Forecast Pool Price to Load

	1999			2000		
	AE-G	**EPGI**	**TAU-G**	**AE-G**	**EPGI**	**TAU-G**
Base PP Forecast	$39.0	$37.7	$38.1	$29.8	$29.5	$30.8
Load + 1.5%	43.5	42.1	43.7	32.5	32.2	33.3
- Change from Base PP	+4.5	+4.4	+5.6	+2.7	+2.7	+2.5
Load - 1.5%	35.3	34.2	34.8	27.6	27.5	28.6
- Change from Base PP	-3.7	-3.5	-3.3	-2.2	-2.0	-2.2
Range of Pool Price Change	8.2	7.9	8.9	4.9	4.7	4.7
Load Forecast (GWh)		52,294			52,540	
3% of Load (GWh)		1,569			1,576	
3% of Load (MW)		179			180	

Thus, a ±1.5% change in annual load causes a ±10%-12% change in Pool Price in 1999 and a ±7%-9% change in 2000.

Source: IPCAA Evidence, Volume II, Section 1, p.12

Other factors, which have a significant effect on the pool price, include the following:

- new generating plant,
- imports, and
- natural gas prices.

The Board notes that the determination of an accurate surplus/shortfall amount depends on the hourly level of generating unit output and the corresponding hourly pool price. The Board, in the "GENCO Deferral Account" section determined that it would be necessary to set up a deferral account with respect to variations in hourly pool price from forecast.

(C) Pool Receipts, Obligation Value Refund and Variable Cost

Pool receipts represent the sum of the product of hourly generation and the corresponding pool price for all hours of the year. The pool receipts of the Utility are the sum of the pool receipts of all the Utility's generators.

3. GENCO/TRANSCO/DISCO
(a) Generation

The UOV refund is the sum of the product of the unit's UOA and the difference between the hourly pool price and the unit's UOP for all hours of the year during which the pool price exceeds the unit's UOP. The obligation value refund of the Utility is the sum of the obligation value refunds of all the Utility's generators.

The variable cost represents the sum of the product of hourly generation and the corresponding incremental energy cost (i.e., variable O&M and fuel costs) for all hours of the year. The variable cost of the Utility is the sum of the variable costs of all the Utility's generators. The UOP was specifically developed to be used in the calculation of the UOV and is intended to reflect the average variable cost of generation.

The Utility forecasts did exhibit some disparities in the variable cost of generation as shown in the following table:

Forecast 1999 Variable Generation Cost

	Generation (GWh)	Cost ($M)	Cost $/MWh
AE-G Results			
Per AE-G	8,596	$ 58.8	$ 6.85
Per EPGI	8,709	64.5	7.40
Per TAU-G	8,773	63.4	7.22
EPGI Results			
Per AE-G	9,237	116.3	12.59
Per EPGI	9,344	119.7	12.81
Per TAU-G	8,979	105.6	11.76
TAU-G Results			
Per AE-G	29,812	95.4	3.20
Per EPGI	29,814	95.5	3.20
Per TAU-G	29,737	95.3	3.20

Source: IPCAA Evidence, Volume II, Section 1, p.11

Board Findings

All three Utilities show very similar results for TAU-G, but there are differences in the cost for AE-G and EPGI. Only a fraction of this difference is explained by the different forecast volumes of generation. In fact, reviewing EPGI's and TAU-G's forecasts for AE-G, TAU-G shows more generation, but a lower total cost. The Board considers that these variances are indicative of the variance that could be expected on an actual basis. The Board considers that the variance between forecast variable cost and actual variable cost should be considered as normal forecast

test year risk. Consequently, the Board has not found it necessary to set up a deferral account to track the variance between forecast and actual variable costs.

(D) Thermal and Hydro Surplus/Shortfall

As noted earlier, the above components of generation volume, pool price, asymmetry effect, pool receipts, obligation value refunds and variable costs all culminate in the surplus/shortfall.

The following tables illustrate the total thermal and hydro surplus/shortfall resulting from the Utilities' modelling for 1999 and 2000:

1999 Net Surplus/Shortfall in Model Runs

($ Million)

Forecasted By:	AE Low	AE High	AE Ave*	EPGI Low	EPGI High	EPGI Ave*	TransAlta-G Low	TransAlta-G High	TransAlta-G Ave*
AE	($5.7)	($3.3)	**($5.0)**	($23.2)	($15.6)	**($19.2)**	$61.7	$63.5	**$62.9**
EPGI	($6.5)	($2.3)	**($4.8)**	($18.2)	($12.5)	**($14.7)**	$56.7	$61.1	**$59.5**
TransAlta-G	($8.6)	$8.7	**$1.2**	($29.6)	($9.0)	**($17.0)**	$18.8	$43.4	**$33.0**

2000 Net Surplus/Shortfall in Model Runs

($ Million)

Forecasted By:	AE Low	AE High	AE Ave*	EPGI Low	EPGI High	EPGI Ave*	TransAlta-G Low	TransAlta-G High	TransAlta-G Ave*
AE	($2.0)	$0.4	**($0.7)**	($6.6)	($3.4)	**($5.1)**	$44.0	$46.4	**$45.2**
EPGI	($0.8)	$1.0	**($0.1)**	($7.0)	($4.4)	**($5.4)**	$41.9	$45.9	**$43.5**
TransAlta-G	($2.4)	$1.0	**($0.9)**	($11.1)	($3.1)	**($6.4)**	$22.0	$40.7	**$34.1**

Sources: AE Evidence, Volume 2, Schedule 2.21; EPGI Evidence, F-31 to F-46; TransAlta Evidence, Section 2.2; Exhibit 58
*Average of all simulation runs

The hydro surplus/shortfall results for 1999 and 2000 are as follows:

Forecast By:	1999 Generation Energy (GWh)	1999 TAU-Hydro Surplus ($M)	2000 Generation Energy (GWh)	2000 TAU-Hydro Surplus ($M)
AE	1,666	15.3	1,666	9.3
EPGI	1,666	12.8	1,667	8.1
TransAlta-G	1,661	3.8	1,658	(3.4)

Source: IPCAA Evidence, Volume II, Section 1, p.10

Board Findings

The Board notes that approximately one-third of the differences in the Utilities' forecast of TransAlta's surplus/shortfall for 1999 is due to forecast differences in the hydro surplus/shortfall. For 2000 all of the differences in the Utilities' forecast of TransAlta's surplus/shortfall is due to forecast differences in the hydro surplus/shortfall. The Board considers that its decisions respecting modeling assumptions and parameters to use in the re-run of the models will provide a reasonable base line surplus/shortfall, which can be used to determine reservation prices.

(3) System Support Receipts

System support receipts or ancillary service revenues represent the compensation paid by the TA to a regulated generator to cover the fixed and variable generation costs incurred in providing system support services. As with a surplus, system support service revenue is considered as a revenue offset to the fixed generation costs resulting in a reduction to the reservation price..

This section of the Decision is primarily a description of the components of system support services. It also contains a summary of the Utilities' forecasting and modeling results respecting system support revenues.

The following table summarizes the ancillary revenue forecast to be received by the generating Utilities:

3. GENCO/TRANSCO/DISCO

(a) Generation

	$ million			
1999	**AE**	**EPGI**	**TAU**	**TOTAL**
1. Voltage control and System Security (Fixed)	2.0	1.8	11.2	15.0
2. Constrained Operations (Fixed)	0.5	4.5	8.6	13.6
3. Constrained on Generation-Trans (Variable)	0.4			
4. Constrained on/down Gen-Oper Res (Variable)	3.5	11.9	2.0	
5. Constrained down Generation-AGC (Variable)	4.3		3.3	
Sub-Total Constrained Operations (Variable)	8.2	11.9	5.3	25.4
Total Ancillary Services	**10.7**	**18.2**	**25.1**	**54.0**

2000	**AE**	**EPGI**	**TAU**	**TOTAL**
1. Voltage control and System Security (Fixed)	2.0	1.8	11.2	15.0
2. Constrained Operations (Fixed)	0.5	4.5	8.6	13.6
3. Constrained on Generation-Trans (Variable)	0.4			
4. Constrained on/down Gen-Oper Res (Variable)	1.0	9.3	2.0	
5. Constrained down Generation-AGC (Variable)	3.2		3.3	
Sub-Total Constrained Operations (Variable)	4.6	9.3	5.3	19.2
Total Ancillary Services	**7.1**	**15.6**	**25.1**	**47.8**

Sources: IPPCA.APL-104; IPPCA.TransAlta-63; Exhibit 35; Decision U97065

Ancillary service revenues are revenues earned by generating units for providing system support and control services to the Transmission Administrator. This revenue is broken down into five primary sources:

1. fixed payments for services arising from the voltage control and system security capabilities of certain equipment that forms part of the generating units;
2. fixed payments for constrained operations of the generating units;
3. variable payments for constrained on generation for (or out-of-merit (OOM)) transmission system support;
4. variable payments for spinning reserve to provide for the loss of other units on the system;
5. variable payments for automatic generation control (AGC) which allows the System Control Center to automatically adjust a unit's output to meet demand changes.

(A) Fixed Payments for Voltage Control and System Security Costs

The Board, in Decision U97065, approved voltage and system security costs of $14,999,470 as part of the overall cost of system support services. The components of the fixed payments for voltage and system security costs are shown in the following table:

(in $)

Category	AE	EPGI	TransAlta	Total
Hydro Motoring			3,000,000	3,000,000
Voltage Support	392,890	456,420	2,409,960	3,259,270
Dynamic Voltage Support	1,293,680	976,080	4,002,720	6,272,480
Power Systems Stabilizers	84,050	175,230	203,540	462,820
Supplemental Governor Response	173,280	142,510	1,098,500	1,414,290
Remedial Action Schemes	19,620		425,580	445,200
Black Start			43,680	43,680
Power System Monitoring	52,150		49,580	101,730
Totals	**2,015,670**	**1,750,240**	**11,233,560**	**14,999,470**

The most significant portion of the voltage and system security cost was referred to as "Dynamic VARS/Voltage Support" (Excitation) at a cost of $6,272,480. These generator excitation costs were broken down by GENCO as follows:

AE	$1,293,680
EPGI	976,080
TransAlta	4,002,720
Total	$6,272,480

EAL engaged the services of Mr. Thorne of D. H. Thorne Consultants Inc. to review ancillary (system support) service costs and tariffs. Mr. Thorne observed that the cost of the generator exciters represented a significant part if not all the cost of the exciters. Mr. Thorne noted that no generator can operate without an exciter and that therefore these costs should be attributed to the costs of generation, not the cost of ancillary service provided from that generator.

Position of TransAlta

TransAlta noted that EAL's consultant, Mr. Thorne, presumed that the excitation costs allocated from generation to transmission reflected virtually the entire cost of the exciters. TransAlta submitted the following:

> To the contrary, 52% of the cost of static excitation systems and 58.4% of the cost of rotary exciters have been allocated to Transmission for the provision of reactive power and system security responsiveness. The allocation reflects the extended range and capability required by these exciters to meet the needs of the power system which are beyond the minimum requirements of the generation itself.[99]

Position of EAL

Mr. Thorne tested the reasonableness of TransAlta's exciter costs as follows:

> Using the present value at 8 % over 10 years of their filed costs multiplied by two (approximately) to reflect the allocation provided in their rebuttal results in an asset value of $53.7 million for the exciters, compared with a new cost of $25.4 million or about double the cost of new excitation. The larger and older TransAlta units range in age from 20 to 40 years. The age factor alone should have resulted in depreciation of at least half of the newer unit exciter costs and most of the older unit exciter costs. The original costs of exciter systems for newer generating units built in the 1970s and 1980s were not greater by a factor of two. The filed information shows that the depreciated exciter costs are greater by that amount.[100]

Mr. Thorne concluded "that the fixed costs for voltage control (excitation) appear to be two to four times the correct amount and no evidence has been provided to substantiate the allocation of these costs between transmission and generation."

EAL adopted the recommendations of Mr. Thorne in its written evidence. EAL noted TransAlta's rebuttal evidence and responded as follows:

> EAL has identified two difficulties with the TransAlta approach. First, TransAlta has offered no support for its allocation of exciter costs between Transmission and generation beyond the mere declaratory statement in its rebuttal evidence. Every generator must have an exciter to operate. As TransAlta has indicated allocating exciter costs to transmission can only be justified if it can be demonstrated that the exciter is required to operate over an extended range of output in order to regulate voltages on the power system. The mere capability to operate over an extended range in itself is not evidence that the exciter is required to operate over an extended range to support the transmission system. TransAlta has not presented evidence that the exciters are in fact operating over an extended range in a dynamic fashion for the purposes of supporting the transmission system. Facing the lack of any evidence to the contrary, and having regard for the fact that

[99] Rebuttal, p.4
[100] Exhibit 197

all generators must have an exciter to operate, all of the exciter costs should be allocated to generation.[101]

EAL submitted that once the exciter costs were put at issue by the evidence presented by EAL, it would be reasonable to expect that TransAlta would have presented additional evidence supporting its position, if it were available. Having regard for the absence of such evidence or any reasonable explanation of the TransAlta approach, EAL continued to believe that the total exciter costs should be allocated to generation.

However, EAL stated that the issue goes beyond cost allocation. It now appears that the approximate $4 million of TransAlta exciter costs is overstated by at least a factor of two and possibly as much as a factor of four. The question is not to which function (generation or transmission) the overstated component of the exciter costs should be allocated; the question is whether TransAlta should be permitted to include these costs in its revenue requirement at all. As noted by Mr. Thorne, the Board approved $15 million for voltage control and system security for purposes of the Gridco and utility refiling in the 1996 Decision.[102] The $15 million included the $4 million for TransAlta exciter costs.[103] However, although the $15 million total cost for voltage control and systems security approved by the Board compared favourably with the costs for US utilities in the Oakridge National Laboratory Report (and as noted by the Board at page 605 of the 1996 decision), the exciter cost portion of those costs does not compare favourably when considered in isolation. For the reasons noted by Mr. Thorne at Tr. p.6221, line 16 and following, the exciter costs appear to be overstated by a factor of 2 or perhaps as high as a factor of four. Also, TransAlta offered no explanation for the fact that the cost included in the 1996 Application is the same as that included for both 1999 and 2000, which suggests that these costs are not being depreciated.

Mr. Thorne recognized the difficulty of comparing the cost of new exciter systems with the cost of exciter systems at the time they were purchased by TransAlta over the past 20 to 40 years. It is not possible to make a direct conversion of older to newer costs. To address this issue Mr. Thorne took the conservative approach wherein the highest, most redundant costs for new exciters are used for comparison purposes. In the opinion of Mr. Thorne, who has considerable experience in the area of facilities design and cost estimation, this is a reasonable approach. In light of the evidence, a reduction of the exciter costs by 50%, which is the lower end of the two to four times range, would be reasonable.

In summary, EAL submitted that TransAlta presented no justification for the percentage allocation of exciter costs to transmission. EAL further submitted that TransAlta failed to provide justification that the total exciter costs are reasonable.

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[101] EAL Argument, p.24-25
[102] Decision U97065, p.605
[103] Decision U97065, p.888

On the basis of the foregoing EAL recommended:

- That the total exciter costs be allocated to generation.
- That the total exciter costs be reduced by 50%.

Board Findings

The Board considers that the following two issues need to be dealt with in order to arrive at an appropriate cost for Dynamic Voltage Support services:

- the total cost of generator excitation, and
- the cost of generator excitation required to provide system support services.

The Board considers that the first issue involves a determination of the portion of total embedded generator costs that are attributable to excitation systems. The Board does not view this as a GENCO revenue requirement issue, as suggested by EAL, but rather an allocation issue to determine the portion of total embedded generator costs (which are already approved and included in the GENCO revenue requirement) that are attributable to generator excitation.

The Board notes Mr. Thorne's evidence that the embedded cost of generator excitation appears to be double the cost of new generator excitation. However, it appears to the Board that Mr. Thorne assumed the generator excitation costs to be all capital related when in fact only 70% are capital related.[104] Taking this into account would reduce the embedded cost to approximately 1.5 times the cost of new generation. During Board examination, Mr. Thorne agreed that:

> At the time these excitation systems were installed, it is true that excitation systems were more expensive, but certainly not by greater than a factor of two.[105]

The Board is satisfied that the above reduction from a factor greater than two to 1.5 and the fact that older excitation systems were more expensive explains the major reason for the cost difference between the allocated embedded costs and the cost of new excitation.

Mr. Thorne also suggested that the present worth of the filed costs (i.e. the 1996 generator excitation revenue requirement) should be considerably less than the cost of new equipment because the plant is 50% depreciated. The Board is not persuaded by this argument since it appears as though Mr. Thorne did not recognize the fact that the capital related portion of the 1996 revenue requirement would decline over time. Had the declining revenue requirement been recognized, the present worth would likely be closer to 50%. Holding the revenue requirement constant at the 1996 level results in a present worth much higher than 50%.

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[104] IPCAA-Gridco-133
[105] Tr. p.6225

The Board also notes EAL's observation that the GENCOs have not reduced the approved 1996 generator excitation costs to recognize accumulated depreciation that has occurred since 1996. The Board considers that the GENCOs should have accounted for changes in generator excitation costs that have occurred since 1996. Accordingly, the Board directs EPGI and TransAlta, in their refilings, to calculate revised generator excitation costs applicable for each of the test years 1999 and 2000 as follows:

- Net plant (i.e. rate base) to be reduced to account for accumulated depreciation for the period 1996-2000.
- Composite rate of return to correspond with the Board's findings in this Decision respecting fair return.
- Income tax, in the case of TransAlta, to correspond with the Board's findings in this Decision respecting Income Tax.
- Maintenance and overhead costs to correspond with the Board's findings in this Decision.

The Board directs that AE's generator excitation costs should be reduced by the percentage reduction (i.e. 7% for 1999 and 8% for 2000) to the requested GENCO reservation price agreed to in the AE negotiated settlement.

The Board, in the absence of a detailed engineering voltage control study, considers that an allocation factor of approximately 50% is reasonable to account for operation over an extended range to meet the voltage control needs of the transmission system. Consequently, the Board will not require a change to TransAlta's 52% and 58% allocation factors.

The Board considers that its findings will not impede the development of a competitive market for voltage control services given the evidence and findings of the Board that the cost of newer technology generator excitation systems are below the Board approved generator excitation costs.

The Board directs EPGI and TransAlta, in their refilings, to reflect the above recalculated Dynamic Voltage Support costs. The Board notes that the change to the AE costs will be dealt with pursuant to the terms of the AE negotiated settlement.

The Board notes that the remaining fixed payments for voltage control and system security in the above table were not at issue in this proceeding. However, for the same reasons as set out above, the Board finds as follows for the remaining $8,726,990 (i.e. $14,999,470 - $6,272,480) fixed payments for voltage control and system security.

The Board considers that the GENCOs should have accounted for changes in the remaining fixed costs of $8,726,990 associated with voltage control and system security that have occurred since 1996. Accordingly, The Board directs EPGI and TransAlta to calculate revised fixed payments for all remaining items other than "Hydro Motoring" applicable for each of the test years 1999 and 2000 as follows:

- Net plant (i.e. rate base) to be reduced to account for accumulated depreciation for the period 1996-2000.
- Composite rate of return to correspond with the Board's findings in this Decision respecting fair return.
- Income tax, in the case of TransAlta, to correspond with the Board's findings in this Decision respecting Income Tax.
- Maintenance and overhead costs to correspond with the Board's findings in this Decision.

For Hydro Motoring energy and capacity costs, the Board directs TransAlta, in its refiling, to use the Rate 790 rate in effect in October 1998 at 50% load forecast and 13.8 MW of Demand consistent with the methodology used in Decision U97065.

The Board directs that AE's remaining voltage control and system security costs should be reduced by the percentage reduction (i.e. 7% for 1999 and 8% for 2000) to the requested GENCO reservation price agreed to in the AE negotiated settlement.

(B) Fixed Payments for Constrained Operations of the Generating Units

The fixed payments for constrained operations are based on the Board's approval, in Decision U97065, of 50% of the fixed cost of a new proxy generation unit being $13,541,255. The fixed payments to recover the deemed fixed costs were allocated to GENCOs as follows:

AE	$451,375	3.33%
EPGI	$4,513,752	33.33%
TransAlta	$8,576,128	63.33%
Total	$13,541,255	100.00%

Board Findings

The Board notes that the above fixed payments were not at issue in this proceeding. The Board also has no evidence to suggest that the fixed cost of a proxy unit has changed significantly since 1996. Accordingly, the Board, for the purposes of this Decision, will not disturb the deemed fixed costs for constrained operation.

(C) Variable Payments for Constrained on Operation for Transmission

In certain instances, a regulated generator is required to operate for purposes of providing system support even though its UOP exceeds the prevailing pool price. The TA then compensates the Utility for providing this service, since the unit would not have been dispatched otherwise. Constrained on transmission support services are provided by the H.R. Milner and Rainbow units

due to their location in the northwest transmission region. The addition of new non-regulated units in the northwest will substantially reduce this role for the Rainbow units. The energy dispatched for these services are forecast in the settlement modeling. The variable revenue received for providing this service is designed to recover the incremental cost of running the units at the desired load less receipts.

Board Findings

The Board, earlier in the Modeling Assumptions section, Part 1–General, Section 3(a)(1)(E), has set the manner in which variable payments for constrained on operation for transmission constraints should be modeled in the EPGI refiling the results of which apply to EPGI and TransAlta. The Board will accept the AE forecast, as approved in the AE negotiated settlement, as a reasonable base line forecast for AE.

(D) Variable Payments for Spinning Reserve

Spinning reserve can be provided in one of two manners - as a constrained on service (the unit is run above its in merit output level; i.e. it is run out-of-merit) and as a constrained down service (the unit is run below its in merit output level; i.e. it is run in-merit at a lower level). The variable compensation is the same as for transmission support for constrained on spinning reserve and the same as AGC for constrained down spinning reserve.

Board Findings

The Board, earlier in the Modeling Assumptions section has set the manner in which variable payments for spinning reserve should be modeled in the EPGI refiling the results of which apply to EPGI and TransAlta. The Board will accept the AE forecast, as approved in the AE negotiated settlement, as a reasonable base line forecast for AE.

(E) Variable Payments for AGC

AGC services are provided by certain thermal generating units (e.g. Sundance, Keephills and Sheerness). The variable compensation for AGC services is the foregone pool receipts while constrained down to provide the service.

Board Findings

The Board, earlier in the "Modeling Assumptions" section has set the manner in which variable payments for AGC should be modeled in the EPGI refiling the results of which apply to EPGI and TransAlta. The Board will accept the AE forecast, as approved in the AE negotiated settlement, as a reasonable base line forecast for AE.

(F) System Support Services Agreements

At the time of the proceeding, only TransAlta had executed a System Support Services Agreement with the TA, ESBI Alberta Ltd. (EAL).

Position of EAL

The TA is required to "set reasonable standards and requirements for system support services and make prudent financial arrangements so that system support services are available and shall ensure that those arrangements are carried out." While EAL had these responsibilities, it argued that, in absence of a System Support Services Agreement or Terms and Conditions, it lacked the authority to impose the reasonable standards and requirements it required. The TA did not have the authority to compel regulated service providers to provide service or to maintain the facilities necessary to do so.

EAL proposed a process to assist parties in arriving at System Support Services Agreements. EAL informed the Board that EPGI and AE had not yet executed System Support Services Agreements because the parties were unable to finalize adverse positions on the issues of information sharing and indemnity. Because the System Support Services Agreements were not executed before EAL's appearance at the proceeding, EAL recommended that the Board impose system support Terms and Conditions in the absence of agreements.

As the two remaining issues were not resolved at the end of the proceeding, EAL requested that the Board issue an early ruling on the indemnity issue. The Board would give the parties a reasonable period (perhaps 30 days) from the date of its ruling on the indemnity issue to either sign the System Support Services Agreements or return the matter to the Board for further adjudication.

Position of AE

AE noted that it and EAL were very close to concluding a System Support Service Agreement. The only outstanding issues were those regarding Transmission Terms and Conditions. Specifically, this involved the confidentiality/provision of information and possibly the indemnity issue. AE wished to register its strong objection to any suggestion that the TransAlta/TA Agreement be imposed on AE.

Board Findings

The Board notes that the issues of confidentiality/provision of information and indemnification, that remained to be negotiated for the System Support Service Agreement between EAL and AE and EAL and EPGI have been settled by the Board under the Transmission Terms and Conditions section of this Decision. Therefore, the Board directs that these provisions also be incorporated into the AE and EPGI System Support Service Agreements as they have been approved for the Transmission Terms and Conditions.

The Board would prefer that parties be given time to develop workable agreements for system support services. Therefore the Board directs that within 30 days following the issuance of this Decision, AE and EPGI are to report on their progress towards reaching agreements on system support services.

(4) GENCO Deferral Accounts

(A) Surplus/Shortfall

The Board, in the modeling accuracy section above, determined that with suitable input parameters and appropriate modeling techniques, it is possible to determine a reasonable baseline forecast of the annual surplus/shortfall dollars by generating unit and GENCO for the purposes of fixing reservation prices for the test years. However, the Board earlier noted that the tightness of the system will result in a volatile pool price during the test years making it difficult to determine accurate surplus/shortfall amounts by unit and by GENCO.

The Board, in this section, must determine whether it is appropriate for pool price and performance risk to rest with the utility or whether deferral accounts should be set up to deal with variations from the baseline surplus/shortfall forecast. The Board, in making its determinations will also have regard to the affect its Decision will have on performance incentives.

EPGI and TransAlta are firmly opposed to any form of generation deferral accounts.

The Intervenors, on the other hand, supported IPCAA's proposals for generation deferral accounts. These include the following:

- GENCO pool price deferral account, where 100% of the difference between average actual and average forecast pool prices is tracked and charged or refunded to customers;
- Volume deferral account, with a 90%-10% sharing between customers and shareholders for changes in surplus-shortfall due to volume of generation. (The Board notes that Mr. Drazen's filed evidence suggested a 75%-25% sharing between customers and shareholders. This suggestion was endorsed by the FIRM Customers in their argument. Mr. Drazen at Tr. p.4432 and IPCAA in argument revised their proposal to a 90%-10% sharing between customers and shareholders);
- Hydro deferral accounts to reflect both the difficulties in forecasting the timing of hydro output and the ability of the Utility to use hydro to set pool prices. The customer share would be 100% and 90% of the hydro pool price deferral account and the hydro volume deferral account respectively.

For convenience, the Board repeats the following tables which illustrate the large variance in the 1999 and 2000 forecasts for surplus/shortfall:

3. GENCO/TRANSCO/DISCO
(a) Generation

1999 Net Surplus/Shortfall in Model Runs

($ Million)

Forecasted By:	AE Low	AE High	AE Ave*	EPGI Low	EPGI High	EPGI Ave*	TransAlta-G Low	TransAlta-G High	TransAlta-G Ave*
AE	($5.7)	($3.3)	**($5.0)**	($23.2)	($15.6)	**($19.2)**	$61.7	$63.5	**$62.9**
EPGI	($6.5)	($2.3)	**($4.8)**	($18.2)	($12.5)	**($14.7)**	$56.7	$61.1	**$59.5**
TransAlta-G	($8.6)	$8.7	**$1.2**	($29.6)	($9.0)	**($17.0)**	$18.8	$43.4	**$33.0**

2000 Net Surplus/Shortfall in Model Runs

($ Million)

Forecasted By:	AE Low	AE High	AE Ave*	EPGI Low	EPGI High	EPGI Ave*	TransAlta-G Low	TransAlta-G High	TransAlta-G Ave*
AE	($2.0)	$0.4	**($0.7)**	($6.6)	($3.4)	**($5.1)**	$44.0	$46.4	**$45.2**
EPGI	($0.8)	$1.0	**($0.1)**	($7.0)	($4.4)	**($5.4)**	$41.9	$45.9	**$43.5**
TransAlta-G	($2.4)	$1.0	**($0.9)**	($11.1)	($3.1)	**($6.4)**	$22.0	$40.7	**$34.1**

Sources: AE Evidence, Volume 2 Schedule 2.21; EPGI Evidence, F-31 to F-46; TransAlta Evidence, Section 2.2; Exhibit 58
*Average of all simulation runs

Position of TransAlta

The absence of deferral accounts was intended to place pool price and performance risk with TransAlta operations, being the entities best able to manage such risks. Such risks also provide TransAlta with an incentive to perform better than forecast, as only TransAlta will suffer if performance is below forecast.

TransAlta provided examples that demonstrated how deferral accounts reduce incentives. The generation example provided in Exhibit 16 establishes that situations exist wherein a deferral account for generator performance would reduce the operator's incentive to perform the most economic repairs on the unit or units.

TransAlta contended that there was general agreement that deferral accounts should be avoided in principle. TransAlta submitted that high risk in and of itself is not a reason to allocate risk to someone who is poorly positioned to manage such risks. TransAlta submitted that when risk is at its highest, the best risk manager, being the operator, should be looked to in order to manage such risk.

TransAlta opposed deferral accounts because not only do they dull incentives, but in some circumstances, may even motivate the utility to "do the wrong thing from a security point of view."[106] TransAlta stated that the Board should reject invitations to establish GENCO deferral accounts for TransAlta.

Position of EPGI

EPGI contended that the evidence demonstrates that the use of surplus/shortfall-related deferral accounts as suggested by certain Intervenors is unnecessary and not in the public interest as it would merely result in reduced performance incentives during a period in the province's history when strong performance incentives are required.

Use of deferral accounts may inexorably serve to shift an owner's focus from minimizing all costs, including outages, to minimizing specific costs, such as labour costs. This is of particular concern during years such as 1999 when supply is tight and performance incentives are critical. As a result, EPGI believes it is critical for the Board to carefully consider the potential costs of putting deferral accounts in place in 1999 and 2000, including:

- lower system reliability;
- less than optimal timing for forced maintenance outages;
- longer forced maintenance outages; and,
- longer planned maintenance outages.

EPGI noted that, with no incentive to shift maintenance to weekends, a generator may decide to perform maintenance during the week for a lower cost where system reliability is not at imminent risk, but where the risk to system reliability may be higher than if the maintenance were postponed to the weekend. EPGI concluded that it is unreasonable and naïve to expect generators to make decisions without consideration of the financial incentives.

Position of AE

AE presented a witness to speak to generation and pool price forecast modeling and related deferral accounts, as it viewed this as a generic issue which could have both direct and indirect impacts upon AE. The fundamental underpinning of AE's position is that at this time it is virtually impossible to design generation and pool price forecast modeling with a reasonable degree of accuracy. As well, minor variations in assumptions can lead to significant variations in the ultimate output of all models currently being employed.

As such, AE concluded that this is an appropriate circumstance to make use of deferral accounts and supports the establishment of same by the Board for all three Applicants in these proceedings. AE noted that the Board had previously approved such a deferral account for AE in the context of its Negotiated Settlement.

[106] Tr. p.3274-3280

Position of IPCAA

Both EPGI and TransAlta have argued that using a deferral account will "dull" the Utilities' incentive to improve performance. TransAlta also submitted a hypothetical example under which a deferral account might cause a utility to choose a different approach to maintenance in a specific instance. The inference was that this would be detrimental to customers.[107] IPCAA considered that the Board must consider the following two questions.

- First, will deferral accounts change the incentives?
- Second, would deferral accounts be disadvantageous to customers?

With respect to the first question, the import of the claim by EPGI and TransAlta is that the performance improvements that they have achieved in the last two years (when deferral accounts were in effect) would have been even greater without deferral accounts. However, that position conflicts with the forecast of decreased performance in 1999-2000 as compared to 1997-1998.

With respect to the second question, what is abundantly clear from the past three years is that the benefits of improved performance experienced by the Utilities would have been kept entirely by them in the absence of deferral accounts. EPGI and TransAlta have enjoyed constantly increasing net surpluses. IPCAA stated the following in reply:

> TAU takes the position that ". . . [s]uch risks also provide TransAlta with an incentive to perform better than forecast as only TransAlta will suffer if performance is below forecast." Of course, it is equally true that without deferral accounts only the utilities will benefit from performance above forecast. EPGI also speaks only of ". . . taking away penalties for poor performance." It is almost as though TAU and EPGI believe that if they pretend that there is no potential for them to make additional profits from increased net surplus then no one will notice. Customers are not nearly so naïve and of course neither is the Board.[108]

It appears that there are three possible courses of action that are open to the Board.

- First, it could try to "fix" the models and the assumptions to produce an "accurate" forecast.
- Second, it could assume that a "reasonable" forecast can be produced by averaging the different results in some fashion.
- Finally, it could use deferral accounts to avoid the problems caused by the large variability and inevitable large variances and results.

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107 Tr. p.705; Exhibit 15, BR.TAU-3; Tr. p.3272ff
108 IPCAA Reply Argument, p.13

3. GENCO/TRANSCO/DISCO
(a) Generation

IPCAA shared the view of AE, that it is simply not feasible to "fix" the forecasting approach, as was attempted in 1996.[109] Despite the refinements and adjustments to the generation forecast that the Board ordered in Decision U97065, the 1996 surplus/shortfall results were quite different than the forecasts. Every year since then the variances have grown.

In theory, one could attempt to develop a number through averaging that, if not accurate, is "reasonable" in the sense that there are balanced chances of favourable and unfavourable variances. The Utilities however have rejected this approach. In spite of the use of common input assumptions, the results of the different models used by the Utilities were not sufficiently consistent that the Utilities could agree that an average of the three forecasts provided a reasonable set of results. The differences between the forecasts can be attributed to the way that the different models deal with the common input assumptions, and also to the different modelling techniques which are available within each model. The Utilities worked together to reconcile these differences, but were unable to come to an agreement on a common set of results.[110]

Moreover, experience suggests that the chance for unfavourable variances to the Utilities is much smaller than that of favourable variances.

Finally, even if the physical factors were equally balanced on the plus and minus side, market power is a factor that cannot be balanced. In addition, the potential for large negative variances, (even if balanced by potential for positive variances) creates additional risk.[111] That risk increases the cost to customers. IPCAA submits that, when all of the options are considered, the use of deferral accounts is the simplest and most effective way of dealing with the issue.

IPCAA therefore recommended: (i) setting the baseline amounts on the basis of 1996-1998 actual results; and (ii) using deferral accounts for variances in pool price, loose juice variances and ancillary service revenue (which is related to loose juice).

IPCAA proposed deferral account mechanisms that used average pool price for thermal units and 125% of average pool price as a baseline for hydro units. Mr. Drazen agreed that a deferral account mechanism that utilized hourly pool prices would be "more precise" and in that case a separate deferral account would not be necessary for hydro units.[112] Mr. Drazen also noted that if the performance bar for generating units were set at nearly the top of the range of the units' actual performance, customers would be protected without a deferral account or with a low sharing percentage to the customers.

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[109] Exhibit 146; AE Application, Volume II, p.G-10
[110] Exhibit 13; TransAlta Application, Binder 1, Section. 2.2, p.4
[111] Exhibit 4, p.3
[112] Tr. p.4419

Position of IPPSA/SPPA

Numerous issues arose during the Phase I hearing which cause IPPSA/SPPA to conclude that the use of deferral accounts is the most suitable way to mitigate risks associated with the 1999/2000 forecast. The use of deferral accounts will bypass the nearly impossible task of choosing a "fair" benchmark forecast of Pool Price, Unit Availability, and Surplus/Shortfall for the two year test period. Moreover, deferral accounts will curb the incentive for generators to make additional profits, at the expense of consumers through exercise of their market power. That is profit over and above the ability they have shown to make profit from surplus generation to date.

IPPSA/SPPA submitted that the existence of incentives to exercise market power will ultimately result in higher costs to consumers both in the short-term (via artificially high and volatile pool prices) and in the long-term (because new entrants will be unwilling or unable to compete in the market). As a result, IPPSA/SPPA supports the Pool Price and Volume deferral accounts proposed by Mr. Drazen. IPPSA/SPPA concludes consumers' interests would be best served through the implementation of surplus/shortfall deferral accounts. Deferral accounts eliminate the need to argue about dueling modeling assumptions, improper input assumptions, and conservative availability forecasts. Deferral accounts curb incentives to manipulate pool price. To impede the Utilities' ability to alter regulated generator unit output to improve the profitability of non-regulated affiliates, the sharing of "insider information" related to pricing and downtime must also be eliminated.

IPPSA/SPPA noted that EPGI and TransAlta control significantly more "marginal price setting" capacity than AE. As a result, EPGI and TransAlta have the greatest ability to exercise market power. IPPSA/SPPA stated "It is not surprising that EPGI and TransAlta support a mechanism that provides a significant financial incentive to exercise market power, whereas AE has agreed to deferral accounts."[113]

IPPSA/SPPA also submitted that the implementation of deferral accounts reduces the level of risk to the Utilities and should result in a corresponding reduction in their rate of return.

Position of the FIRM Customers

Forecasting pool prices and surplus/shortfall calculations is problematic due to high sensitivity of prices and uncertainty in modeling. There is the potential for significant differences between forecast and actual pool prices, and forecast and actual surplus/shortfall amounts due to two separate phenomena. Specifically, volatility in pool prices, because of the tight supply-demand situation present in Alberta, and uncertainty in modeling those prices, even if the same assumptions are used.

In this regard, the FIRM Customers agreed with Mr. Drazen that attempting to find a point forecast of pool prices and surplus/shortfall calculations is "playing with the customers'

[113] IPPSA/SPPA Reply Argument, p.9

money."[114] The FIRM Customers also agreed with Mr. Drazen's observations that the variability is uncontrollable by customers and partially controllable by generators.[115] This is an area where the Utilities clearly have more information than the customers. As a result, the FIRM Customers are not confident a fair forecast is likely.

The FIRM Customers discussed the difficulty in arriving at a fair forecast as follows:

Volatile Pool Prices

Pool prices are extremely volatile given the tight supply-demand relationships currently present in Alberta. Therefore, any forecasts of relationships dependent on pool prices (generation surplus/shortfall measures, DISCO payments for generation, etc.) are likely to be potentially fraught with error.

Moreover, because of the tight supply situation, pool prices are also sensitive with respect to supply, and supply is uncertain. For instance, as Mr. Drazen points out, the construction of an unregulated generator at Sundance could change pool prices by as much as $10/MWh in the last half of 1999.[116] Mr. Marcus also points out the timing of new supply creates risk.[117]

Other factors affecting the volatility of pool prices include gas prices and the level and pricing of imports.

Modeling Uncertainties

In addition to uncertainty in demand and supply affecting pool prices, there is also uncertainty in modelling assumptions. AE and EPGI use PROSYM whereas TransAlta uses ENPRO. These models, run with common assumptions, produce very similar results for AE and EPGI. However, TransAlta's model skews the result, producing a $30 million smaller surplus for itself. Explanations for the differences provide little assistance or comfort to parties in their search for a reliable forecast. Half of the differences arise because TransAlta assumes its hydro dispatch will produce considerably less surplus than EPGI and AE's models. However, TransAlta's actual hydro performance in 1998 is closer to the results modeled by AE and EPGI for 1999/2000. As Mr. Drazen also points out, even though TransAlta's model is otherwise consistent with the aggregate pool price results of the other Utilities, it forecasts lower on-peak prices and higher off-peak prices.

"Loose Juice" Availability

All of the models run with a five-year average of forced and maintenance outage rates. However, performance has been improving, particularly for the Genesee units as they come into maturity.

[114] Tr. p.4334
[115] Tr. p.4401
[116] Exhibit 136, Volume II, p.12-13
[117] Exhibit 159, p.10

In addition, capital maintenance projects are likely to increase Utility output and revenue. The extent to which the benefits of such capital maintenance are included in the five-year average is unknown. A deferral account for the next two years (with a majority of funds to ratepayers, but with significant shareholder participation) will create the appropriate balance between efficiency and fairness.

Utilities Should Not Be Given Incentives to Use Market Power to Affect Pool Prices

In addition to the unpredictability of pool prices, there are concerns that with three large generators, market power can be exercised in Alberta.[118] This concern is also identified as an important item in the London Economics study of the AIS.[119] The entire IAT process was designed to reduce market power through the sale of the right to bid generation into the pool to a number of new entities. While the potential for exercise of market power remains in the current world, a pool price deferral account will go a long ways to reducing the benefits one may otherwise achieve by "gaming the system."

The FIRM Customers noted TransAlta's claim that the risk should be allocated to the party best able to manage it. The FIRM Customers submitted that TransAlta's claim is presumptuous, given that virtually every Intervenor active in this proceeding, both end-use customers and municipal DISCOs are willing to take the risk away from TransAlta. Simply put, the cost of leaving the risk with TransAlta and EPGI is too high. TransAlta would be given too much money because of its poor generation surplus/shortfall forecast, and its ability to exercise market power. In addition, the compensation that TransAlta is requesting in its return on equity for bearing the risk is excessive. While TransAlta may argue abstractly that it is better suited to take the risk, it wants too much money for providing that service. The FIRM Customers submitted that customers are better off taking the risk in this two-year interim period than paying TransAlta to take it on their behalf.

Position of ENMAX

Given the uncertainty of the forecasts and the magnitude of the differentials, ENMAX is of the view that the Board has little choice but to establish a baseline and a deferral account for surplus/shortfall around pool price and output. Since the pool price is intended to be set by a "free and open" market with no one entity able to manipulate it to their advantage, it would be prudent to set up a deferral account with 100% "true up" to prevent the GENCOs from benefiting from the exercise of market power. Deferral accounts do not solve the problem of market power but they serve to remove some of the incentives to abuse market power.[120]

The generating Utilities have responded well to the powerful incentives to improve the performance of their generating units even during periods when deferral accounts were in place. Since 1996 the average generating performance has exceeded the five year average in each year.

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[118] Tr. p.4311, p.4315, p.4317
[119] Tr. p.4339
[120] Tr. p.4412

3. GENCO/TRANSCO/DISCO
(a) Generation

The generating Utilities continue to advocate the use of the five-year average FMORs. Clearly the enhanced performance since 1996 should be recognized. It would therefore be appropriate to base the "bar" for generating performance on the average FMOR of the three years since restructuring of the industry has taken place. If the "bar" is not set above the proposed all inclusive five-year average FMOR suggested by the generating Utilities, a deferral account to capture differences would be appropriate.

If the Board approves a deferral account, the appropriate level of sharing between GENCOs and customers depends on the degree to which the "bar" is raised. ENMAX recommends a 90/10 split if using the unadjusted five year average FMORs. Use of the most recent three years FMOR would merit a 75/25 split.

ENMAX noted that the evidence of Mr. Drazen is that deferral accounts do not remove efficiency incentives[121] and that EPGI and TransAlta have testified that deferral accounts will not alter their commitment to operational excellence.[122] Consequently, there is no downside to the use of deferral accounts. ENMAX strongly urges the Board to establish deferral accounts.

Position of LE/RD

LE/RD supported the Drazen proposal for pool price and volume deferral accounts. LE/RD also suggested that appropriate guidelines must be put in place with respect to the operation of the accounts including audit and transparency requirements contemplated in the AE negotiated settlement.

The arguments that TransAlta put forward only address generally why deferral accounts are not appropriate in principle. The difficulty is that the argument does not deal effectively with the two major problems that were apparent with respect to the Utilities' Applications, namely the reliability of the forecast, and, whether or not the Utilities are, as a result of their forecasts, truly bearing the risks, or simply preserving for themselves the likelihood of earning excess profits. In circumstances where the reliability of the forecast is suspect (if, for no other reason, because of the significant differences between the forecasting Utilities with respect to 1999/2000 surplus shortfalls), and past performance indicates that for whatever reason, the Utilities appear to have consistently out-performed their targets or forecasts, LE/RD suggest that TransAlta's theoretical arguments in opposition to a deferral account should be rejected.

Board Findings

The Board considers that pool prices will be difficult to forecast with confidence throughout 1999 and 2000 due to the following:

- the tight supply demand situation

[121] Tr. p.4317
[122] Tr. p.654, p.2180

3. GENCO/TRANSCO/DISCO
(a) Generation

- the timing of new sources of supply
- the pricing of imports
- natural gas prices
- the potential for the exercise of market power

The uncertainty surrounding these factors make it difficult to accurately forecast with confidence hourly pool prices. Further, the Board considers that the Utilities should not be given incentives for the potential exercise of market power to affect pool prices. In these circumstances the Board considers it appropriate to utilize a deferral account to deal with the uncertainty of pool prices. The Board considers that the deferral account mechanism should be utilized hourly for greater accuracy and based on the average hourly forecast determined from the EPGI and TransAlta refilings.

Accordingly, the Board considers it appropriate to establish and maintain, for each of 1999 and 2000, a deferral account in which 100% of the difference between the actual hourly and forecast hourly pool price for all EPGI and TransAlta thermal and hydro generating units is accumulated and borne by customers. The Board directs that a pool price deferral account be established by EPGI and TransAlta for the 1999-2000 period with the amount to be deferred in respect of each hour to be calculated as follows:

> Pool price deferral = (Actual pool price-Forecast pool price) x (Forecast generation by unit) + (Forecast unit obligation value – Actual unit obligation value)

The Board directs that the above deferral account formula should use a forecast hourly pool price, forecast hourly generation by unit and forecast hourly UOV developed for EPGI's and TransAlta's thermal generating units as follows:

- Develop an average hourly pool price, average hourly generation and average hourly UOV by thermal unit by averaging EPGI's PROSYM modeling iterations.
- Develop an average hourly pool price, average hourly generation and average hourly UOV by thermal unit by averaging TransAlta's ENPRO modeling iterations.
- Develop the forecast average hourly pool price, forecast average hourly generation and average hourly UOV for EPGI's and TransAlta's thermal units by averaging the above EPGI and TransAlta averages.

Further the Board directs that the above deferral account formula should use a forecast hourly pool price, forecast hourly generation by unit and forecast hourly UOV developed for TransAlta's hydro generating units as follows:

- Develop the forecast average hourly pool price, forecast average hourly generation and average hourly UOV for TransAlta's hydro units by averaging EPGI's PROSYM modeling iterations.

3. GENCO/TRANSCO/DISCO
(a) Generation

The Board considers it important to maintain performance incentives designed to keep units on line during tight supply situations. The Board is not persuaded that performance incentives are maximized with a volume deferral account. However, the Board considers it important to set the performance standard at a reasonable and demonstrably achievable level. The Board considers that the Utilities have had three years (i.e., 1996-1998) of experience operating under the restructured environment. The Board considers it important that operating performance statistics from the pre-restructured era not be included in the development of forecast modeling parameters. Accordingly, the Board directs, for the purposes of the refiling, that all forecast modeling parameters be determined using actual performance data over the three-year period 1996-1998. The Board is satisfied that, with the above method of determining performance standards, it would not be appropriate to establish a volume deferral account for EPGI and TransAlta generating units.

The Board considers that, with its directions respecting hydro modeling in a previous section of this Decision and its decision to use hourly pool price for the pool price deferral account for both thermal and hydro generating units, it is not necessary to set up a separate deferral account for hydro generating units.

The Board will deal with the effects that its determinations may have on the allowed fair return in Business Risk and Capital Structure and Return, Part 1–General, Section 3(h) and 3(i) of this Decision.

(B) Ancillary Services

The uncertainty surrounding pool prices for 1999 and 2000 also affects the forecast of ancillary service revenue. The Board, in this section, must determine whether it is appropriate for pool price and performance risk respecting ancillary services to rest with the utility or whether deferral accounts should be set up to deal with variations from the baseline ancillary services forecast. The Board, in making its determinations will again have regard to the affect its decision will have on performance incentives.

EPGI and TransAlta firmly opposed any form of deferral accounts for ancillary services.

The Intervenors, including EAL, supported proposals for deferral accounts for ancillary services.

Position of EAL

Uncertainty in forecasting ancillary service payments is best demonstrated by a comparison of forecasts to actuals. The EPGI October 1998 re-forecast amount of $13.6 million for variable system support services in 1998 compared to the actual values of $11.7 million show clearly the magnitude of forecast uncertainty that exists. For this reason and the reasons outlined in EAL's argument, it is clear that there is significant uncertainty surrounding the forecast of ancillary services revenue and a deferral account is warranted.

Position of IPCAA

IPPCA proposed that the following method be used for ancillary services accounts:

> The ancillary services deferral account for EPGI will use as its baseline the filed variable ancillary service receipts for EPGI. The fixed variable ancillary services receipts baseline should be $6.3 million. The deferral accounts for TAU's ancillary services will be separate for hydro and the operating reserve and automatic generation control services. The hydro deferral account will consist of 90% times average pool price times 135% less UOP times 70 GWh. The volume is calculated using 1997 and 1998 actual data. The deferral accounts for AGC and spinning reserve will set the baseline volume at an average of 1996, 1997, and eight months of 1998 data pro-rated times the difference in the average pool price less UOP. The deferral accounts on ancillary services will be similar to the previous two deferral accounts; 100% pool price deferral and 90% of volume.[123]

Board Findings

The Board considers that its findings respecting the forecast of ancillary revenues earlier in this Decision will improve the accuracy of the forecast and provide a solid base line from which variances can be measured for the purposes of accumulating differences in a deferral account.

The Board is not persuaded that its findings respecting deferral accounts for surplus shortfall (i.e., 100% pool price deferral; no volume deferral) are equally applicable for ancillary services. The Board considers there is a high probability of significant volume variance due to the uncertainty of the amount of reserves that can be procured from hydro units and the effect of new generation on the requirements for spinning reserve. Accordingly, on balance the Board directs EPGI and TransAlta to establish a deferral account for ancillary service revenue in which the revenue variance is shared 90% to customers and 10% to the Utilities. The Board considers that this sharing will provide sufficient incentive for the Utilities to ensure performance of their units to provide the required support services as well as appropriately deal with the risk of price and volume variability.

(b) Transmission

(1) Transmission Planning Guidelines

The TA as an interested party in the 1999/2000 Electric Tariff Phase I General Rate Application, raised a number of issues regarding transmission planning. During the proceedings, the Alberta Department of Resource Development (DRD) facilitated a consultative process, with industry participants, to attempt to reach a consensus respecting transmission planning issues and to determine if there was a need for any legislative clarification.

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[123] IPCAA Argument, p.37

The DRD issued Transmission Planning Guidelines (TPG)[124] in June 1999, which clarified the policy intent and scope for transmission planning and transmission ownership pursuant to the EU Act. The DRD's stated intent is to introduce any amendments required to the EU Act to implement this policy the next time the EU Act is opened in the legislature.

The key features of the TPG[125] include:

- The TA is accountable for total transmission planning.
- Under certain conditions the TA will seek competitive ownership for new transmission facilities.
- TFOs will participate in transmission planning as requested by and under the overall accountability of the TA.
- Accountabilities are identified for the TA and the TFOs for bulk and non-bulk transmission facilities.
- Customer needs for timely service, system access and confidentiality will be met.
- Customers are provided, where practical, with the ability to choose if competition or direct assignment will determine ownership of a new transmission facility or if the customer will own the facility.
- TFOs are committed to providing the information needed by the TA to respond to customer inquiries for system access.

Position of TransAlta

TransAlta indicated the TPG will not have a significant impact on its capital forecast. TransAlta indicated that only a few of the projects in its capital forecast are affected by the guidelines.[126] TransAlta maintained that its capital forecast was reasonable due to the nature of the projects and the fact that some have already been assigned to TransAlta.

TransAlta noted that:

- Projects less than $10 million will be directly assigned to the respective TFO. TransAlta indicated that all projects in the 1999 application, close to or exceeding the $10 million limit, have already been assigned to TransAlta.
- Transmission customers will have an option to construct their own facilities, have the TA directly assign the project, or have the project competitively bid.

TransAlta considered that customers have always had the right to construct their own dedicated transmission facilities. For many years, TransAlta has supported this by offering a primary service credit for those customers. The Board notes that all customer projects over $1 million in the 1999 application have been assigned to TransAlta. In the year 2000, TransAlta indicated that

[124] Exhibit 180
[125] Exhibit 180
[126] Exhibit 185

it was working on approximately $9 million worth of capital additions for customer projects.[127] As well it noted that it is working on projects that could have a cash flow of up to $37 million for 2000.[128] TransAlta further stated that in its view the customers in the pool of projects are not customers that would have a high desire to move into a contestable environment.[129]

TransAlta noted that IPPSA/SPPA asked the Board to impose a $1.5 million threshold for direct assignment rather than $10 million. TransAlta submitted that it is inappropriate to ignore the TPG, particularly when such guidelines were created after consultation with interested parties and the Government has announced its intention to include the threshold in the form of a regulation or statute in the future.

Position of AE

In response to cross-examination at the hearing, AE indicated that the TPG are workable and that it plans to observe and follow the guidelines as they are currently set out. AE indicated at the hearing that it supported a review of these guidelines, in the 2002 time frame.

Also at the hearing, AE submitted that a $2 million threshold would not increase the likelihood of competitive procurement for transmission facilities in the province. It indicated that Section 4.1 of the TPG impose obligations on the TA to make decisions of this nature.

AE indicated that in Appendix A of the TPG, there is an expectation that competitively procured transmission facilities will be regulated by contract rather than by inclusion in rate base.[130]

In response to questioning on whether the TPG would restrict its ability to build or to compete to build bulk transmission facilities in the province, AE indicated that it does not see anything that precludes it from competing for bulk or non-bulk transmission facilities when they are competitively procured.

Position of EPTI

EPTI noted IPPSA/SPPA's suggestion that transmission projects of greater than $1.5 million should go to competitive procurement and TCE's submission that a threshold of $2 million should be used. EPTI noted that the TPG, which were the result of extensive discussions among interested parties and the DRD, define the threshold at $10 million. The TPG cover many issues, and reflect considerable "give and take" among interested parties. The Minister of Resource Development (the Minister) has indicated that appropriate legislative changes will be made to implement the TPG in the near future. EPTI was involved in the process of developing the TPG and is committed to following them.[131]

[127] Tr. p.5775
[128] Tr. p.5775
[129] Tr. p.5777
[130] Tr. p.6085
[131] Tr. p.6128

EPTI contended that there is no evidence, which supports the reasonableness of anything other than the $10 million threshold set in the guidelines. Further, having regard to the fact that the TPG were found to be acceptable to most parties on an overall basis, it would be inappropriate to "cherry pick" one aspect of the TPG for potential change. EPTI noted TCE's acknowledgement that "cherry picking" should not occur with respect to the TPG.

EPTI submitted that, in suggesting changes to the TPG, IPPSA/SPPA and TCE are merely attempting to have the Board usurp the DRD's consultative and legislative process for dealing with this issue. The mere fact that these parties take issue with one aspect of the TPG does not demonstrate that there is anything unreasonable about the TPG or that the DRD's process is somehow flawed. EPTI contended that the DRD process has proven successful in resolving important issues to date, and there is no basis for these parties to suggest that the Board should interfere with either the process or the result. Acceptance of the IPPSA/SPPA suggestion would improperly harm future DRD consultative processes.

EPTI indicated that there is no need, as suggested by IPPSA/SPPA, for the Board to "provide some clarification as to how the guidelines are to be interpreted."[132] Since the document is currently a government policy document, the DRD will presumably clarify the document in consultation with interested parties as may be required from time to time.[133]

Position of ENMAX

ENMAX supported the TPG noting that they clarify the roles of the TA and the TFO and should enable the various constituents to move forward.

ENMAX noted that it is also important to recognize that the business interests of the various parties are diverse, and will not always be aligned. It indicated that disputes will arise, and will need to be resolved in a reasonable time frame if transmission system access services are to be maintained at an adequate level. ENMAX indicated that it might be difficult for the TPG to achieve their objectives as in their current form they rely on co-operation between the parties and leave some elements to be resolved by future agreement. For these reasons ENMAX submitted that the TPG need to be revised to remove ambiguities and given legal status through legislation or regulation.

ENMAX noted that TransAlta, EPTI, AE and EAL have all stated that they intend to act in accordance with the TPG.[134] ENMAX also noted TCE's concerns with the TPG with respect to improper delegation of authority by the Board and also expressed concern with the $10 million threshold for transmission projects that would go to competitive bid. ENMAX noted that IPPSA/SPPA suggested that the Board direct the TA to set the threshold at $1.5 million until the TPG becomes "law." ENMAX indicated that lowering the threshold to $1.5 million would have

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[132] IPPSA/SPPA Argument, p.57
[133] EPTI Reply Argument, p.14
[134] Tr. p.5951-5952, p.6081-6083, p.6128, p.6187

serious implications to the complex and long term process of ENMAX's planning and operation of transmission facilities in the Calgary area. The higher risk of various parties operating transmission facilities in an urban area would require revisiting other portions of the TPG to address, among other things, municipal consent and access agreements and operating agreements.

In ENMAX's view it would not be appropriate for the Board to issue directions to the TA that would amount to "cherry picking" by the interested parties. While the TPG cannot be construed as a negotiated settlement between the interested parties, the Board should recognize that they were developed by the DRD following a process where all interested parties were able to participate.

It is ENMAX's submission that to the extent the Board finds it necessary to "adopt" the TPG, the Board should do so as a package and not make any adjustments to them.

Position of IPPSA/SPPA

IPPSA/SPPA stated that at the $10 million threshold, very few projects will be competitively procured,[135] noting that over the past 10 years, only three projects would have been considered. Therefore, competitive forces, as envisioned by the EU Act, will never have the opportunity to be exerted for the benefit of consumers.

IPPSA/SPPA contended that if the Board accepts the TA's approach, the $10 million limit is not required. IPPSA/SPPA submitted that an independent TA was hired to make the appropriate determinations when a project should be direct assigned or competitively procured to the benefit of consumers. The proposed clause 4.3.1(b) frustrates the ability of an Independent TA to be effective and hinders the development of competition.

IPPSA/SPPA submitted that while everyone has agreed to accept the TPG, there remains the issue of who will perform the planning function, the TA or the Utilities.[136]

IPPSA/SPPA submitted that it should be clear that the TA has the obligation to provide system access to consumers. It should also have the discretion to directly assign or competitively procure projects. These duties require the TA to take the lead role in providing system planning in Alberta. IPPSA/SPPA also submitted that the Board should provide some clarification as to how the TPG are to be interpreted.

Position of LE/RD

LE/RD contended that while the TA retains overall responsibility for transmission planning and retains discretion with respect to transmission facility ownership, there are directions contained in the TPG which govern the exercise of such direction. Those directions include direct

[135] Exhibit 195
[136] Tr. p.5913, p.6081, p.6128, p.6187

assignment of the ownership of facilities, not subject to competition pursuant to Section 4.3 of the guidelines, to the TFO in whose distribution service area the facilities will be located. Furthermore a review of the Bulk and Non-Bulk System Accountabilities set out in the TPG revealed that a significant amount of responsibility remains with TFO for analysis, planning and detailed design.

Position of TCE

TCE noted that the Board has before it the issue of how it will respond to the TPG as well as the issue of potential subdelegation of its authority. In both cases, TCE submitted that the Board must ensure that it does not improperly abdicate its authority.

TCE indicated that the Board is not bound by DRD letters,[137] nor is the Board bound by a letter from the Minister or by a policy statement from the Department or the Minister.[138] It also submitted that ministerial policy directives are not binding on the Board, and it is up to the Board to determine what weight, if any, it will give to the directive.

TCE noted the issue of weight to be assigned to the guidelines is not an easy answer. The Minister has indicated not only that the guidelines represent government policy, but, as well, that it is the intention of the Department to pursue an amendment to EU Act to legislate the principles indicated in the present guidelines.

TCE agreed with the TPG, but submitted that a lower threshold for competition is in the public interest. TCE is concerned that the $10 million threshold for transmission facility projects to go to competitive bid has the potential to severely limit the opportunity of new parties to become TFOs. TCE indicated that the vast majority of transmission facility expansions in recent years have been under the $10 million threshold.[139] TCE noted the TA's discretion, pursuant to section 4.5 of the guidelines, which recognizes the right of a single customer:

- to choose to construct and own the transmission facilities itself;
- to direct the TA to directly assign the construction or ownership of the transmission facilities to a TFO (either existing or new) of the customer's choice; or
- to direct the TA to place the transmission facilities out to competitive bid.

TCE supports the customer choice provisions and certain other provisions of the TPG. It also submitted that the Board could find that a lower threshold of, say $2 million, was in the public interest. However, TCE also noted that, in this instance, it may not be appropriate for the parties to pick and choose which provisions of the TPG they will follow.

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[137] Tr. p.1827
[138] Tr. p.5607
[139] Exhibit 195; Tr. p.5934-5944, p.6086-6087

Subject to concerns with respect to the threshold discussed above, and to the arbitration provisions of the TPG (which potentially raise the same concerns as Section 9 of the TFO Terms and Conditions), TCE submitted that the Board could find the TPG to be in the public interest.

Position of EAL

EAL indicated that the TA's role and responsibility for transmission system planning has been the subject of review through the DRD, which resulted in the TPG. EAL has agreed to abide by the TPG in the interim period.[140] As well, the three Utilities[141] have indicated that they are prepared to live with them.

Board Findings

The Board notes that the main issues with respect to the TPG are:

- Concerns with respect to the proper delegation of authority by the Board.
- The weight to be assigned to the guidelines by the Board and clarification as to how the guidelines are to be interpreted.
- The $10 million threshold below which transmission lines may be directly assigned to the respective TFO.

While the guidelines may not be a "negotiated settlement," the Board recognizes that they were developed with the participation of interested parties. The Boards also acknowledges that although the parties have not reached consensus on all points within the TPG, there has been general support from the industry participants. The Board notes that TransAlta, EPTI, AE and EAL, all of whom assisted in developing the TPG, intend to act in accordance with them.[142] The Board supports and encourages the parties to continue to strive for consensus with respect to the TPG.

With respect to the concerns raised by IPPSA/SPPA, the Board notes that the TPG indicate that the TA will take the lead role in providing system planning in Alberta and has the obligation to provide system access to consumers as well as the right to directly assign or competitively procure projects.

With respect to the "delegation of authority" and "weight to be assigned the TPG" issues raised by TCE, the Board notes that the Minister has indicated that appropriate legislative changes will be made to implement these TPG in the near future. Accordingly until the TPG are legislated, they do not bind the Board. The Board does not consider that the proposed TPG result in the Board abdicating its authority. Rather, the Board considers that the TPG have assisted interested

[140] Exhibit 196
[141] TransAlta, Tr. p.5913; AE, Tr. p.6082; EPTI, Tr. p.6128
[142] Tr. p.5951-5952, p.6081-6083, p.6128, p.6187

parties in resolving and clarifying transmission and ownership issues, not only for the 1999/2000 GTA, but also in the future as new issues may arise.

The Board notes the request by IPPSA/SPPA, "for the Board to provide some clarification as to how the guidelines are to be interpreted."[143] The Board notes that there is still opportunity for interested parties to raise any necessary clarifications with the DRD prior to incorporation into legislation. The Board does not consider that any clarification of the TPG is required for the purposes of the 1999/2000 GTA.

The Board notes that only TCE and IPPSA/SPPA raised issues with respect to the $10 million threshold, both suggesting it should be lower. The Board considers that a threshold lower than $10 million will not significantly affect the 1999/2000 forecast TFO transmission capital additions. Accordingly, the Board does not consider it necessary to make any ruling on the level of the threshold for the purposes of this Decision.

On a related issue, the Board will decide on the appropriateness of the TFO's capital additions forecast in the Transmission Capital Additions Section 3(b)(3) of this Decision.

(2) Duplication of Planning Costs

Position of EAL

EAL indicated that it contested the planning full time equivalents (FTE) of TFOs in order to avoid duplication of transmission planning costs. EAL submitted that it had overall accountability for transmission system planning. It noted that an existing TFO, a new TFO or a customer may construct transmission additions or alterations. Where it is economical and efficient to do so, the TA may assign some or all of the TA's function to a third party, including an existing TFO.

EAL indicated that in order to increase competition, all parties should be treated in a fair and non-discriminatory manner. This will not occur if existing TFOs are permitted to recover planning costs in their regulated rates while third parties are not. Therefore in 2000 and beyond, no planning costs for transmission additions or alterations should be included in the TFO's General & Administrative (G&A) forecast. Where the TA assigns planning functions to the TFO, such costs would be paid to the TFO directly from the TA just as they would for any other third party with whom the TA contracts for services.

With respect to EPTI and AE's planning related costs, EAL initially indicated that these costs were related to "planning" as defined by the TA. In subsequent discussions with EPTI, EAL was advised that the two FTEs do not perform transmission system planning functions, rather they are responsible for maintaining the integrity of existing transmission facilities. Based on this

[143] IPPSA/SPPA Argument, p.57

information, EAL submitted a letter dated 8 June 1999[144] indicating that it no longer had concerns with the cost associated with these two FTEs. In argument, EAL indicated that it also has withdrawn its request that system planning costs be removed from AE's revenue requirement.

EAL noted that TransAlta has 13 FTEs involved in planning related matters,[145] whereas AE and EPTI have 1.5 FTEs and 2 FTEs respectively. EAL contended that based on the size of TransAlta's transmission system relative to that of AE and EPTI, it would be reasonable to assume that approximately two or three FTEs would be required by TransAlta to fulfill the planning function. EAL noted, however, that in 1999 it directly assigned the planning function for a number of projects to TransAlta. Therefore, it was difficult for it to accurately assess the number of FTEs that would be required to fulfill these functions. Consequently, EAL cannot determine the number of TransAlta FTEs that duplicate the planning function of the TA in 1999. EAL submitted that if the Board is satisfied that TransAlta has established the need for 13 FTEs, a reduction in FTEs is not required for 1999.

EAL noted that according to TransAlta, 90% of the costs associated with the thirteen FTEs are charged to capital[146] and the remaining 10%, which amounts to $150 000 annually, is charged to operating costs. EAL submitted that the requirement for planning FTEs is driven by the forecast level of capital additions. In 1999 TransAlta has included in its forecast transmission capital additions of $49.8 million, for which the current FTE count is presumably sufficient. In 2000, the forecast transmission capital additions drop to $26.8 million, approximately 46% of the 1999 level. Assuming the full thirteen FTEs can be supported by the workload associated with the forecast level of capital additions in 1999, EAL submitted that the FTE requirement in 2000 should be reduced by approximately six positions.

EAL noted that according to TransAlta, the 13 FTEs may be required to discharge responsibilities that may be delegated to TransAlta by the TA. TransAlta should not recover such costs in its revenue requirement. The TA's customers, who pay the wires tariff on a flow-through basis, should not compensate TransAlta for keeping extra planning staff on hand in case the TA delegates a project. If the TA delegates a project to a third party, including TransAlta, the TA will compensate the third party directly on a contractual basis. Allowing TransAlta to include the cost of planning FTEs in its revenue requirement provides TransAlta with a competitive advantage over other third parties that may compete for the same contract, thereby eliminating the competition and reducing the number of options available to the TA.

TransAlta should also be required to demonstrate that none of the 13 FTEs in its Facilities Planning group duplicate the planning functions of the TA. In the absence of greater clarity with respect to the number of TransAlta FTEs involved in duplicative transmission planning duties,

[144] Exhibit 192
[145] Tr. p.5731; Tr. p.5757
[146] Exhibit 185, p.2

EAL suggested in argument that FTE costs for 2000 be allocated as a function of the capital project's budget. TransAlta's argument provides no additional certainty and, therefore, EAL believed that its recommendation to reduce TransAlta's FTEs by six makes the most sense.

Therefore, EAL recommended that TransAlta's forecast level of transmission capital additions in 2000 be reduced by $607,000, which accounts for the reduction of six in FTEs to support the forecast amount of transmission capital spending. This would reduce the forecast level of transmission capital additions in 2000 to approximately $26.2 million.

EAL provided the following summary of its position on this matter:

- EAL has no recommendation with respect to planning FTEs for 1999.
- For 2000, TransAlta's forecast level of transmission capital additions should be reduced by $607,000 to account for the reduction in planning FTE expenses that should accompany the reduction in workload between 1999 and 2000.
- The Board should direct that planning costs for system additions and/or reinforcements not be included in the G&A in future TFO GTAs and that duplication of costs between the TA and the TFO be eliminated.

EAL submitted that 1999 could be treated as a transition year, having regard for the fact that the TPG were not issued until midway through the year, but EAL submitted that duplication of planning costs should be prevented for 2000.

Position of IPPCA

IPPCA noted that, according to TransAlta, there is a "significant amount of work" for the 13 FTEs in their Planning Group related to responsibilities delegated by the TA. IPPCA submitted that TransAlta should not be paid "up-front" for any services it may supply to the TA in competition with others. If the TA makes requests of TransAlta, then it should be required to negotiate with the TA for a fee for those services (just as any other supplier would be required to do). This includes both requests from the TA and acceptance of responsibilities delegated by the TA.

IPPCA indicated that any FTEs that are related to services provided by the TA should be removed from TransAlta's requested revenue requirement.

Position of IPPSA/SPPA

IPPSA/SPPA indicated that a large number of transmission projects have been directly assigned in 1999, resulting in the 13 TransAlta FTEs which may be the same in 2000. IPPSA/SPPA noted that the capital budget proposed by TransAlta would in all likelihood be fully expended in 1999 and 2000 due to the number of direct assignments made. Implementing the TA's approach will not harm TransAlta's shareholders, however, it will benefit consumers.

IPPSA/SPPA recommended that the Board adjust the FTE transmission planning employees' costs as per EAL's evidence.

Position of TransAlta

TransAlta submitted that the costs included for the 13 FTEs in the Facilities Planning Group are reasonable. It noted that issues appear to have arisen due to the difference in planning definitions amongst the parties. TransAlta noted that EAL stated "...the term (planning) was not used, in fact, to mean the same thing by each of us, respectively."[147]

TransAlta indicated, that "the Facilities Planning Group has a far broader role than transmission planning as defined in the guidelines." TransAlta also submitted[148] that it had reduced its staff complement from 24 FTEs in 1995 to 13 FTEs for 1999 and 2000 and had reduced its transmission staff by over 140 employees.[149] TransAlta also noted[150] that "... approximately 90 percent of the labor of this group is charged to capital. After charges to capital, the net operating cost is approximately $150,000 per year."

TransAlta submitted that the TPG make it clear that much of the transmission planning accountability has been left with the TFOs. TransAlta noted that, notwithstanding the position taken in its evidence, EAL acknowledged in cross-examination that:

> We are not suggesting that the owners of existing transmission facilities should not have planning staff for the purposes of operating and maintaining their existing facilities and for the purposes of ensuring that new interconnections with their existing facilities do not pose a threat to the integrity of their facilities.[151]

TransAlta submitted that it has demonstrated that the 13 FTEs in the Facilities Planning Group is reasonable, recognizing the transmission planning accountabilities which remain with the TFOs and recognizing the many other accountabilities of this group.

TransAlta noted that EAL has slightly modified its initial position that the cost of all planning FTEs be denied, recommending that TransAlta be allowed 2 to 3 FTEs. EAL's recommendation fails to take into account the fact that much of the transmission work carried out by TransAlta's Facilities Planning Group does not fall within what EAL considers to be "planning". Further, the direct assignment of many projects to TransAlta clearly requires that it have staff to carry out this role. TransAlta noted that IPPSA recognized that the large number of transmission projects that have been directly assigned make-up the 13 FTEs "utilized in 1999 and potentially in 2000 as well." TransAlta submitted that EAL's recommendation is unreasonable and must be rejected.

[147] Tr. p.6173
[148] Tr. p.5719
[149] Exhibit 185
[150] Tr. p.5719
[151] Tr. p.6147

TransAlta also noted that EAL has also related the number of FTEs for planning to the magnitude of capital expenditures, suggesting that since less capital is required in 2000 than in 1999, the FTEs required for planning should be reduced proportionately. There is no evidence to suggest that the number of FTEs required for planning are directly proportional to the magnitude of capital expenditures. TransAlta submitted that projects with a lower level of expenditure can require considerably more effort from the planning group for activities such as siting than a project with a substantially higher level of expenditure. In addition, there is evidence to suggest that the FTE forecast in 1999 may be low. For example, TransAlta forecast two FTEs for siting work, as outlined in EAL.TAU-55 (revised), although it currently has 4½ to 5 FTEs working on siting activities.[152] TransAlta submitted that its FTE forecast for planning purposes is reasonable and no reductions are warranted. For the same reasons, TransAlta submitted that EAL's recommendation that the capital forecast be reduced by $607,000 in 2000 should be rejected.

It noted that EAL has also suggested the possibility of paying TransAlta for any planning services that it provides for EAL. The flaw in this proposal is that TransAlta would have to charge a much higher rate to have staff strictly for the purpose of responding to requests for planning services from EAL.[153] As a result, capital project costs would increase. Accordingly, TransAlta submits this proposal would result in higher costs to customers and should be rejected.

Position of EPTI

EPTI stated that it forecast $140,000 for two FTEs to perform system planning functions.[154] These FTEs are responsible for maintaining the integrity of EPTI's existing transmission facilities and ensuring that the interconnection of new facilities does not threaten the integrity of its system.[155] These FTEs are not involved in any detailed facility design that would be required in order to participate in a competitive procurement process.

Although EAL initially took issue with the inclusion of costs for these two FTEs in EPTI's application, EAL provided the Board with a letter dated 8 June 1999[156] which indicated that EAL no longer had concerns and would not pursue the issue further. EAL advised the Board that it was withdrawing the recommendation set out in paragraph 61(b) of its submission which took issue with these costs.[157]

EPTI therefore submitted that the costs related to these two FTEs are necessary for the proper functioning of EPTI's business, are reasonable and should be approved by the Board.

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[152] Tr. p.5924
[153] EAL Tr. p.5728
[154] EAL-EPTI-29
[155] EAL-EPTI-46
[156] Exhibit 192
[157] Exhibit 203

Position of AE

In its Application AE indicated that it had included a modest cost associated with transmission planning. During the course of the proceedings AE provided clarification to the TA regarding its planning role while the TA clarified its definition of transmission system planning.[158]

As a result, the TA confirmed that is no longer opposed to AE's planning FTEs.[159] AE no longer considers this matter to be an issue.

Position of ENMAX

ENMAX noted that the FIRM Customers expressed concern with duplication of transmission planning costs, and recommended that the Board "closely monitor these costs in conjunction with the potential cost savings and efficiencies that should actually be realized through this new process".

ENMAX agreed that avoiding duplication of costs and searching for efficiencies should be the aim of all parties. However, ENMAX also noted that an inevitable consequence of introducing competition is that there will be some overlap of functions. It is simply not feasible for TFOs to somehow mothball transmission planning and design functions, and then re-create the expertise whenever the TA assigns a project. TFOs must also be in a position to assess transmission system requirements on an on-going basis, and to carry out due diligence (need, system impacts, design, price) on proposed projects. Consequently, a competitive world, with a system of checks and balances between interested parties, will not necessarily introduce savings at every level. ENMAX suggested that any future examination by the Board should also look for larger scale efficiencies that result from competition versus centralized planning.

Position of the FIRM Customers

The FIRM Customers expressed concern regarding the addition of extra and, apparently, incalculable costs to the transmission planning function for 1999. The FIRM Customers noted that EAL is accountable for all transmission planning in Alberta and is responsible for forecasting the need and costs of transmission additions or alterations. Consequently, the FIRM Customers stated they were concerned that the TA was unable to determine how many FTEs are required to fulfill the planning function for directly assigned projects.

The FIRM Customers noted that TransAlta indicated that when transmission-planning accountability is taken into consideration, the 13 FTE costs are reasonable. When EAL compared TransAlta to AE and EPTI, EAL recommended a more reasonable number for TransAlta. However, EAL chose not to recommend any reductions for 1999, preferring to leave that to the Board.

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[158] Tr. p.6146
[159] Tr. p. 6169-6170

The FIRM Customers noted that EAL stated that "EAL believes it can perform that system planning function just as well as the 3 TFOs or better for the same price or less."[160] The FIRM Customers noted that this is perhaps the first hard evidence of the introduction of competition in transmission services.

As a minimum, based on the submissions of EAL, the FIRM Customers recommended that TransAlta's 1999 revenue requirement for the transmission planning FTEs be reduced from approximately $1 million to $700,000, a reduction of $300,000.[161]

Board Findings

The Board notes that the main issue with respect to the possible duplication of planning costs is what transmission planning costs should be allowed in the TFO's forecast of G&A costs for 1999 and 2000, and beyond.

The Board notes that EAL had sought and obtained clarification of the costs that were included in EPTI's and AE's forecast of transmission planning FTEs. As a result, EAL no longer had any issue with the inclusion of those TFOs' transmission planning FTEs costs in their revenue requirements, since these activities did not duplicate or otherwise conflict with the TA's planning mandate. The Board agrees that EPTI's and AE's FTEs are reasonable.

The Board notes TransAlta's submission that the FTE issue had arisen in part because of a difference in definition of transmission planning between the TFO and the TA, thus costs attributed to this function meant different things to different parties. TransAlta further submitted that the TPG left much of the transmission planning and design accountability with TFOs. The Board notes that TransAlta's Facilities Planning Group is also involved with activities such as siting.

The Board notes ENMAX's submission that a consequence of introducing competition is that there will be some overlap of functions and it is not feasible for TFOs to somehow mothball transmission planning and design functions, and then re-create the expertise whenever a project is assigned by the TA. The Board agrees with ENMAX that the TFOs must be in a position to assess some transmission system requirements (i.e. directly assigned and maintenance projects) on an on-going basis.

The Board notes that EAL asked the Board to direct TFOs not to include, in future GTAs, transmission planning costs that duplicate the TA's costs. IPPCA submitted that none of the transmission planning costs should be allowed in TransAlta's G&A costs. The Board believes this is an issue to be addressed in the next GTA, as more experience with the TA and TFO's new responsibilities is gained. The Board, however, disagrees with IPPSA/SPPA that the Board should adjust the FTE transmission planning employees' costs as per EAL's evidence, since the

[160] Tr. p.6175
[161] Tr. p.5725

TFO's planning group is involved with direct assigned projects and siting issues. The Board accepts the TFO's explanation for the 1999/2000 period and believes that a co-operative approach between the TFOs and the TA in dealing with this issue is in the best interest of consumers.

The Board notes that with respect to TransAlta's FTEs, EAL was unable to determine whether or not this number should be reduced for 1999, since it had already directly assigned a number of projects to TransAlta for 1999. EAL made no recommendation with respect to FTE costs for 1999.

The Board notes that TransAlta indicated that "... approximately 90% of the labor of this group is charged to capital. After charges to capital, the net operating cost is approximately $150,000 per year." [162] The Board believes that this is a somewhat irrelevant argument because costs are still incurred.

The Board is prepared to accept TransAlta's 1999/2000 transmission planning costs, which will be allowed in its forecast, recognizing however that the industry is in a transitional period with new processes yet to develop.

The Board directs that, in the post 1999/2000 timeframe, the TFOs should be consistent in what they include in planning costs. Also the Board directs that the TA and the TFOs address, in the next GTA, the staff planning requirements in order to minimize any duplication of service and costs. For example, with respect to general system additions and improvements, the Board would expect the TA to provide the majority of the system planning function. At the next GTA, the Board directs the TFOs to bring forward their recommended guidelines, after consultation with the TA, for resolving any perceived or unfair advantages that regulated TFOs might have in bidding on unregulated projects.

(3) Capital Additions

TransAlta is forecasting new capital additions of $52.5 million in 1999 and $37.5 million in 2000. TransAlta indicated that 20% of the capital additions are required to maintain the physical integrity of the transmission system to ensure safe and reliable operation, while 20% is required to provide capacity or system improvements to supply general load growth or to resolve supply reliability concerns. TransAlta indicated that 15% of the capital requirement is to fund a variety of projects including initiatives, line moves, urgent repairs and the Y2K project.

The following table provides a comparison of forecast to actual results.

[162] Tr. p.5719

3. GENCO/TRANSCO/DISCO
(b) Transmission

TRANSALTA							
Comparison of Forecast to Actual Results ($million)							
1996 GTA Forecast	1996 Actual	1997 Forecast*	1997 Actual	1998 Forecast*	1998 Reforecast	1999 Forecast/ Not directly assigned	2000 Forecast/ Not directly assigned
35.9 (SPPA.TAU-10b)	15.9 (Exh.64)	N/A	27.0 (Exh.64)	N/A	22.5 (Exh.64)	52.5/18.7	37.5/29.6

* negotiated settlement

EPTI's 1999 and 2000 capital additions are described in its Application, section 3.4.1.1 and Schedules T-17-1999 and 2000, EAL-EPTI-04 and 51, IPCAA-EPTI-21. In summary, EPTI's transmission rates for 1999 and 2000 reflect forecast capital additions of $6.8 and $7.7 million, respectively. A detailed breakdown and comparison of forecast to actual results is provided in Schedule T-18 to the Application.

The following table provides a comparison of forecast to actual results.

EPTI							
Comparison of Forecast to Actual Results ($million)							
1996 GTA Forecast	1996 Actual	1997 Forecast	1997 Actual	1998 Forecast	1998 Reforecast	1999 Forecast/ Not directly assigned	2000 Forecast/ Not directly assigned
7.3	5.8	5.4	5.5	8.5	8.0	6.8/2.7	7.7/2.4

In Section 3.4.1.1 of its Application, EPTI indicated that the variance between its 1997 forecast and actual was less than $0.1 million. The variance between the 1998 forecast and 1998 reforecast is $0.5 million. $0.2 million of this variance was caused by an industrial customer's decision to cancel a transmission line that the customer had requested.

AE is forecasting new capital additions of $41.1 million in 1999 and $18.1 million in 2000. Schedule 3.81 shows increases in transmission's total rate base for 1998 and 1999 forecast over 1997 actuals. Additions for the AEC Pipeline load, Willingdon and Heisler 144/72-kV transformers, 9L948 Paintearth – Metiskow single pole trip and recloser and Lloydminster substation, contribute $24.8 million to the 1999 increase. A further $2.1 million is for tele protection life extension, SCADA associated capital costs and communication equipment. There is a one-time adjustment to 1999 total rate base to functionalize general property plant and equipment to Generation, Transmission and Distribution resulting in a net increase of $12 million to the total transmission rate base. Further explanation of this adjustment is provided in AE's Application, General, tab Cost Functionalization.

The following table provides a comparison of forecast to actual results:

3. GENCO/TRANSCO/DISCO
(b) Transmission

AE							
Comparison of Forecast to Actual Results ($million)							
1996 GTA Forecast	1996 Actual	1997 Forecast*	1997 Actual	1998 Forecast	1998 Reforecast*	1999 Forecast/ Not directly assigned	2000 Forecast/ Not directly assigned
11.5	13.5	N/A	15.8	59.6	N/A	41.1/5.8	18.1/6.7

*negotiated settlement

Position of EAL

EAL believed that the funds forecast by TransAlta and EPTI for transmission additions and alterations should not be included in their respective revenue requirements. EAL contended that it would be in the best interests of consumers to have those funds included in the revenue requirement of the TA, since it has no incentive to over-forecast the capital requirements for transmission additions or alterations. In the event that the TA were to over-forecast, it would return any over-recovery to customers through the TA's Annual Wires Cost deferral account.

EAL notes those transmission system projects, up to $10 million, will normally be directly assigned to the TFO subject to the discretion of the TA.

EAL noted that if the forecast capital requirements for transmission additions or alterations are included in the TFO revenue requirements, there is an incentive to over-forecast which would benefit the shareholder. If the forecast were too low, the shareholder would pay the difference. Both these factors contribute to the incentive to over-forecast.

EAL submitted that including the forecast capital requirements in the TA's revenue requirement addresses the uncertainty as to who will ultimately construct a facility. EAL noted that if the cost of a project is $10 million or less, there is no assurance that it will be assigned to the TFO. The TA may decide to proceed with an RFP. The project proponent may also request that the TA put the project out for competitive bid or the customer may request a third party to construct the line on its behalf. If forecast costs for unidentified projects are included in the TFO revenue requirements, there will be double counting of costs, as the TFO will collect its full revenue requirement through its rates. As well a third party would pay the TFO if that party constructed the facility.

EAL noted that once a project is brought into service, the TA would pay the TFOs a return of and on capital. This is similar to the current situation where the TFO forecasts a cost of transmission additions but does not earn a return of and on capital until a project is brought into service.

EAL noted that there would be greater scrutiny of capital costs, since the TFO cost estimates will be subject to TA review prior to the facilities application process. If the detailed costs estimated by the TFO are too high, the TA will not support the project before the Board in a facilities case.

EAL recommended that the forecast capital requirements for transmission additions or alterations be removed from the revenue requirement of TransAlta and EPTI.

Position of IPCAA

IPCAA noted that TransAlta has identified the Shell Scotford 240/138 kV as a project which meets the TPG criteria for competitive procurement. TransAlta has stated that: "... it believes it would not be appropriate to make this project contestable."[163] IPCAA submitted that since the Shell Scotford project meets the requirement in the guidelines for competitive procurement, it should be removed from TransAlta's approved forecast of transmission capital expenditures.

Position of IPPSA/SPPA

IPPSA/SPPA indicated that the traditional utility prospective forecast methodology is where a forecast of potential transmissions projects is made and a capital cost estimate is produced. The capital projects approved by the Board is the basis for rate base additions during the test year(s), regardless of the actual amounts invested in transmission projects. During the test year(s) the Utilities do not recover the full capital costs invested, but recover the annual capital-related expenses (return, depreciation and tax) which are reduced in the first year due to the mid-year rate base convention.

IPPSA noted that if the actual expenditures are lower or higher than forecast, utility shareholders receive the benefit or suffer the loss of the capital related expenses in the test year(s) only. In the case of under-forecasting, the capital expended is included in the next application to the Board. If utility shareholders suffer, it is only in the short term.

IPPSA noted that there are several problems with this approach. A review of Exhibit 195 shows that a majority of new transmission projects in the past decade were built, or triggered, by industrial customers. It submitted that industrial loads are more difficult to forecast than residential or commercial loads. IPPSA noted that TransAlta indicated that it has a "pool" of capital projects, as it is not certain on a forecast basis, which transmission projects will be implemented.[164]

IPPSA noted that if a transmission capital project does not materialize, then shareholders may benefit from the capital related expenses noted above, however, the sales revenue will be lower. Similarly for the reverse situation, if capital expenditures are greater than forecast, shareholders suffer from loss of capital earnings, but benefit from increased sales revenues.[165] In either case all is trued up in the next rate case and the risk to shareholders is mitigated. Since utility shareholders earn a return on capital, there is an incentive for Utilities to over spend.

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[163] Exhibit 185, p.3.
[164] Tr. p.5774-5775
[165] Tr. p.5782-5785

IPPSA/SPPA submitted that as a result of industry restructuring, the ability of the Board to effectively test these capital expenditures has diminished.

IPPSA/SPPA submitted that in the emerging competitive marketplace, it is impractical for a utility to try to forecast the level of capital it will expend. Therefore, prospective rate making is no longer practical.

IPPSA/SPPA indicated that the approach put forward by the TA, which calls for the TA to include in its revenue requirement a forecast for transmission related projects during the test year is preferable. As projects are developed during the test year(s), the developing party is appropriately compensated. In the case of direct assignments, the TA will pay the direct assignee utility their development and capital related expenses during the test year(s).[166] IPPSA indicated that the assignee would include the newly expended capital into its rate base, in its next application to the Board.

IPPSA/SPPA noted that from the TA's perspective, their revenue requirements only include the development and capital related expenses during the test year(s). If the TA under or over forecasts, adjustments are made during the next filing. The TA shareholders are not at risk for these forecasts and therefore there is no incentive for the TA to forecast anything other than its best estimate.

IPPSA/SPPA noted that AE expected in the future that there would be two transmission capital forecasts; one from the TFOs for their forecast of direct assigns and one from the TA for competitive procurements.[167] IPPSA submitted that this approach has problems because the TA has discretion over which projects are direct assigned. One of the goals of restructuring is to minimize regulatory costs, not increase them.

Position of the FIRM Customers

The FIRM Customers indicated that EPTI has significantly increased its forecast transmission capital spending in 1998-2000 compared to previous years. EPTI's evidence[168] shows forecast spending levels in 1998-2000 approximately $2 million higher in than in 1996-97.

The FIRM Customers submitted that, although none of the individual transmission projects in EPTI's capital budget exceed $700,000, the overall level of expenditure was questionable.[169] Specifically, EPTI's forecast capital expenditures are triple those recorded in the 1992-1995 time

[166] The assignee utility may be a corporation other than one of the applicants. Unlike distribution, there are no service areas for transmission. If a corporation accepted a direct assignment, they would be required to file a tariff with the TA to recover their capital costs.
[167] Tr. p.6115-6116
[168] Exhibit 136, Vol. III, p.3-2
[169] Exhibit 3, p.S-29 to S-32

frame. EPTI spent only $2.9 million per year in 1992-1995 as compared to $5.5 to $5.8 million in 1996-97 and an average of $7.5 million forecast per year in 1998-2000.

The FIRM Customers submitted that EPTI has a history of over forecasting transmission capital additions going back to the 1996 GTA. At that time, it was demonstrated that it over forecast its transmission capital additions in each of the years from 1992-1995.

Based on its review, the FIRM Customers recommend a capital spending forecast for EPTI of $6 million per year for 1999 and 2000. This recommendation is based on consideration of the 1996-97 values, adjusted slightly upward in consideration of inflation.

The FIRM Customers noted TransAlta's capital budget for transmission projects for 1996 was in the amount of $35.9 million, whereas actual additions were only $15.9 million.[170] Of the approximately $20.0 million difference, the FIRM Customers submitted that almost $10 million is represented by capital maintenance programs. The FIRM Customer noted that TransAlta indicated that the majority of the maintenance was deferred and the "new processes are reflected in the 1999 and 2000 forecasts for Transmission maintenance...." A further $6.7 million relating to "Metering due to Industry Restructuring additions" resulted from deferrals, an Industry Canada dispensation and design innovations. In the end result, the actual amount spent was $4.0 million less than forecast because of reductions in cost.

The FIRM Customers submitted that TransAlta's transmission capital forecast should be reduced by 20% overall, noting concerns with regard to unidentified projects, System Capacity Increases, Specific Customers and the Cheviot Mine Project. Further, to the extent there is any duplication of costs forecast by the TA, there should be further reductions to TransAlta's transmission capital forecast.[171]

The FIRM Customers provided the following comments on these concerns:

- Unidentified Projects
  The FIRM Customers noted that TransAlta indicated a number of projects had not yet been identified. For example, only $500,000 of the total forecast of $2.5 million for "efficient transmission operation improvements" had been identified. TransAlta also indicated that it has a "pool of potential projects" for transmission customers having a cost of approximately $9.0 million.

[170] SPPA.10(b)
[171] Tr. p.5774, p.5782

- System Capacity Increases
  The FIRM Customers noted that TransAlta has forecasted $4.2 million for 1999 and $2.0 million for 2000 of "system capacity increases" which "they have not all been committed to."[172]

- Specific Customers
  The response to IPCAA.TAU-116 indicates that the $8.8 million forecast for transmission customers, identified as "Other" is a forecast amount of $2.3 million for projects under $1.0 million and $6.5 million is for unidentified customers "based on historical experience". The FIRM Customers submitted that given the historical experience, the amount of $6.5 million does not appear to be justified.

- Cheviot Mine Project
  TransAlta's forecast included capital expenditures totaling $3.0 million in 1999 and 2000 on the Cheviot Mine Project. Since a recent court ruling will result in a one year delay in the project,[173] the FIRM Customers submitted that all expenditures related to this project should be deleted for both 1999 and 2000 until there is firm indication this project will proceed.

- Excess Land
  TransAlta indicates it currently owns two parcels of land for future substation development stating that:

> These parcels were purchased for about $39 000 for the Westcott station near Didsbury, and another parcel purchased for about $800 000 for a proposed Northwest Calgary 500/240/138 kV substation. FIRM Customers noted that these parcels are included in rate base.[174]

The FIRM Customers noted that in support of the northwest Calgary parcel TransAlta indicated:

> There is consideration being given by ENMAX, ourselves, and EAL for the possibility of a 240 to 138kV switching station in the north side of the city of Calgary, and the detailed studies as to which location we would put the station at have not been conducted yet. So there is a possibility that it could go in either of these two locations.
>
> The one described as northwest Calgary would be relatively large. It was purchased this size as a potential termination for a north/south 500kV line, which is included in EAL's ten-year plan as an alternative. Should that alternative be

[172] Tr. p.2514
[173] Tr. p.2520
[174] EAL.TAU-92

> pursued, this would be a possible site for that 500kV termination, but that would probably be beyond five years.[175]

The FIRM Customers expressed concerns with respect to these lands. First, TransAlta has held this land in rate base for the last seventeen years without ever having a concrete plan for any type of a substation or other use. In the FIRM Customers' view, TransAlta should have notified the Board and customers it intended to include an asset that did not meet the "used or required to be used" test previously adopted by the Board. Second, regardless of whichever plan TransAlta adopts, only one site would be required.

The FIRM Customers submitted that the $800,000 cost of the 159.97 acres of land, for the northwest Calgary site, should be removed from rate base and deemed non-Utility. Further, the Company should dispose of this land and distribute the proceeds of the sale to TransAlta's customers in accordance with the following procedures outlined by TransAlta:

> The gain or loss associated with the disposition of property, including land, done in the ordinary course of business would be credited to accumulated depreciation. If the land in northwest Calgary referred to at transcript pages 3642 to 3647 is sold because it is no longer required, the sale would be in the ordinary course of business and the gain or loss would be credited to the accumulated depreciation account.[176]

With regard to the land near Didsbury, it appears there is only a small likelihood it will be used in the near or imminent future. It is the FIRM Customers' position that the $39,000 purchase price and any other costs associated with the administration and maintenance of this land should be transferred into PHFFU unless, or until, better information is provided as to the imminent need for this land.

The FIRM Customers supported, the recommendation of the REAs to remove 80% of the $10 million cost of the Novacor independent power producer (IPP) expansion from TransAlta's forecast rate base.

Position of REAs

REAs noted that the Novacor project is forecast to cost $10 million dollars. The REAs submitted that there was no evidence presented as to whether or not Novacor was paying anything towards the incremental costs caused by the generator's need to access the market.

In discussing customer contributions, TransAlta advised[177] that "in this particular case, the TA has exercised what they would claim to be a right to take this customer over as a direct customer

[175] Tr. p.3643
[176] Exhibit 129; Tr. p.3647
[177] Tr. p.2758

of their own as an industrial system." REAs submitted, however that if it means that the customer contribution costs will be paid to the TA, then it expects that the TA in turn would pay them to TransAlta. Consequently, other customers should not be required to bear these costs through this application. Alternatively, if Novacor ultimately pays the customer contributions to TransAlta, again other customers should not be paying these costs. Using the numbers set out in the Authorization for Expenditure Summary filed by TransAlta, the amount of export capability to the Grid is 360 MW, with a need for standby capacity of 90 MW from the Grid and a nominal plant size of 450 MW, the customer contribution should be about 80% of the forecast project cost. This equates to $8 million dollars which, the REA submitted should be removed from the forecast rate base.

Position of ENMAX

ENMAX indicated that although the Cheviot Mine project will not be going ahead in 1999 or 2000,[178] TransAlta has not reduced its forecast additions as it expects the monies will be used elsewhere. ENMAX submitted that the costs for those projects which have been reduced, delayed or eliminated should be removed from the forecast.

ENMAX submitted that there was ample justification for a negative contingency on capital expenditures for TransAlta's generation and transmission business units. It is not possible for the Board and intervenors to evaluate the merits of all capital additions forecast. It is also not desirable for these parties to micro-manage the affairs of TransAlta. ENMAX submitted that a negative contingency from the forecast should be established, an amount approved and the decision on which projects to undertake should be left to TransAlta. Given the historical variances, this is the de facto practice adopted by TransAlta. ENMAX recommended that the Board impose a 25% negative contingency on TransAlta's generation and transmission capital additions.

Position of LE/RD

LE/RD noted the suggestion that transmission capital expenditures should not include those projects that have not been directly assigned at the present. It indicated that those projects should be dealt with on an "as needed and directly assigned basis" with no prior capital approvals. LE/RD therefore see no compelling reason to delete any project that has not currently been directly assigned, from forecast capital expenditures. It indicated however that this does not mean that the Board should not examine the details of the forecast to ensure that the forecast costs are reasonable, that the project is one which fits within the likely TFO ownership criteria, and that the project is likely to proceed within the test years. In other words, the TFOs are still required to demonstrate the reasonableness and prudence of their forecast transmission expenditures.

[178] Tr. p.1701

Position of TransAlta

TransAlta submitted that its capital forecast is reasonable for the following reasons:

- the 1999 and 2000 forecast is below (excluding the Nova/Union Carbide projects in 1999) the historical average;
- any delay in customer projects has an offsetting delay in revenue;
- TransAlta is working on $9 million worth of customer project additions for 2000 at the time of filing and currently this pool of potential projects has an approximate cash flow of $37 million for 2000; and
- the TPG has no significant impact on the capital forecast.

Accordingly, TransAlta submits that EAL's recommendation to remove capital costs not planned and approved by EAL is unwarranted.

TransAlta noted that it has centralized the accountability for transmission and distribution capital management, including the forecasting and approval of expenditures. TransAlta has also included capital additions in its Application that have a higher level of certainty of proceeding than in past filings. In addition, TransAlta has created a project initiation process whereby if a project included in the Application is canceled or delayed beyond the test period, there is a high probability that other projects not included in the Application will be required.

TransAlta indicated that as outlined in Response to Undertaking of Mr. Bryan at Tr. p.2519,[179] the transmission capital additions average from 1992 to 1998 is $38.7 million in 1999 dollars. TransAlta's forecast for 1999 and 2000 is $52.5 and $37.5 million respectively. Excluding the Nova and Union Carbide project additions of $19.6 million in 1999, the forecast is $32.9 and $37.5 million for 1999 and 2000 respectively. Thus, the 1999 and 2000 forecast additions are less than the historical average.

At the hearing[180] TransAlta indicated that no construction contribution was forecast for the Nova Joffre project due to the expected amount of standby load. This was incorrect and TransAlta should have forecast a contribution from NOVA equal to the full capital cost of $10 million.[181]

With regard to transmission customer project delays, these projects are included in both the capital additions forecast as well as the revenue forecast. Regarding the Cheviot Mine project, TransAlta indicated[182] that, to the extent that the capital additions for this project are delayed, the forecast additional revenue from this customer is also delayed.

In TransAlta's submission, the recommendation of EAL must be rejected for two reasons:

[179] Exhibit 92
[180] Tr. p.2756
[181] TransAlta Application Section 3.3 – Transmission CWIP Continuity
[182] Tr. p.2518

- first, many of the projects listed on Attachment 1[183] have been assigned to TransAlta by EAL or are acknowledged by EAL to fall within TransAlta's responsibility, and
- second, many projects initially on the list have been replaced by others, a number of which have been assigned to TransAlta by EAL.

TransAlta noted that a number of projects that EAL has taken exception to are planned maintenance projects, which are required to maintain the integrity of the existing transmission system. As stated in Section 28(2) of EU Act and agreed by EAL,[184] maintenance of the transmission facilities is the responsibility of the wire owner. EAL also agreed[185] that the items identified under paragraph 3, "Transmission Planned Maintenance" in EAL's evidence are properly TransAlta's responsibility.

Also, as stated in EAL's response to TransAlta's Information Request No. 4, the Y2K Project and associated costs listed, were included in Attachment 1 in error, and therefore, should be included in TransAlta's revenue requirement.

TransAlta indicated that as demonstrated in its cross-examination of EAL, EAL has directly assigned to TransAlta several projects not specifically included in its Application. For example, the Nelson Lake and Namaka projects, worth $4.3 and $1.2 million respectively, are projects that have been directly assigned by EAL but are not specifically included in its Application. Another example is the installation of four capacitor banks in southern Alberta. Also, as Mr. Marshall noted, there are a number of other projects such as the Dow IPP Interconnection breaker, Air Liquide IPP Interconnection, Old Man Dam Interconnection, Taylor Chute IPP Interconnection and ANG Cochrane transformer that have been assigned to TransAlta by EAL, but are not listed in its Application. In summary, approximately $9.2 million worth of projects have been directly assigned to TransAlta that were not specifically identified in its Application. EAL testified[186] that since EAL filed their evidence they have directly assigned many, if not all, of the capital projects in TransAlta's service area to TransAlta.

TransAlta notes that the FIRM Customers recommended that land near Didsbury and Northwest Calgary should be removed from rate base. TransAlta noted that the land near Didsbury cost less than $40,000 and is not material. With respect to the parcel northwest of Calgary, TransAlta indicated that it may be required for a major transmission facility in the mid-term and it would be imprudent to dispose of it until a final decision on such a facility has been made.

TransAlta submitted that with respect to transmission capital projects the Board must reject EAL's recommendation that the Board disallow the projects identified in EAL's Attachment 1. The evidence of TransAlta, which was essentially confirmed by EAL under cross-examination,

183 EAL Evidence
184 Tr. p.6175
185 Tr. p.6163
186 Tr. p.6204

establishes that many of the projects are ones that clearly fall within TransAlta's responsibility and, while the particular suite of projects identified in the TransAlta Application may have changed, it is clear that those that have not been processed have been replaced by others. Further, it has been EAL's practice to direct assign many of these projects to TransAlta. All of this, in TransAlta's submission, confirms the reasonableness of its transmission capital forecast.

Finally, TransAlta notes that removal of the capital costs as recommended by EAL and exclusion of the additional projects not in the Application would force TransAlta to seek a rate adjustment each time a project is added. In TransAlta's view, such approach would place an economic burden on it and on the Board.

Position of EPTI

EPTI submitted that Section 29(1) of the EU Act requires an owner of transmission facilities to prepare a tariff setting out rates for use of its transmission facilities. Section 51(1)(a) of the EU Act provides that the Board shall have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover its capital costs if the costs are prudent.

EPTI submitted that capital additions for 1999 and 2000 are prudent. EPTI noted that other parties' interest in the Corporation's 1999 and 2000 capital additions were limited to the following areas:

- the level of EPTI's forecast capital expenditures for 1999 and 2000 compared to actual results and the level of EPGI's forecast capital expenditures in previous years compared to actual results;

EPTI provided a detailed breakdown of all capital expenditures in its Application on Schedule T-18, page S-33. By excluding costs which are related to Y2K work, the average increase in capital expenditures for 1998, 1999 and 2000 is $0.7 million over the 1997 actual.[187]

EPTI's capital expenditures increased in 1998, 1999 and 2000 from previous years primarily due to the need to replace defective and aging equipment, specifically its 72 kV transmission infrastructure. Dr. DeSarkar testified:[188]

> Sir, we have higher capital expenditure because our infrastructure, the transmission infrastructure is fairly old, and we need more replacement and refurbishment as the years go by. For instance, our 72 kV system has an average age of about 35 years, so they are getting old, and they require more maintenance and capital expenditure to keep them in working order.

[187] Schedule T-18, line 29
[188] Tr. p.1167

The increase is also related to EPTI's proposal to provide for a minimum inventory of spare materials at a cost of $0.4 million in 1999 and $0.6 million in 2000 to ensure prompt response to failures of EPTI's 240 kV transmission facilities.[189]

> EPTI noted that in response to EAL-EPTI-04, it identified a number of "type faults". Therefore EPTI is forecasting an increase in capital expenditures in 1999 and 2000 of $0.6 million in 1999 and $0.8 million in 2000 over 1997 actuals to address these faults. As well, safety related expenditures are forecast to increase in 1999 and 2000 by $0.4 million over 1997 actuals. These expenditures are required to implement recommendations from substation building fire code audits and to make substation grounding improvements. Environmental-related expenditures are forecast to increase in 1999 and 2000 by $0.4 million over 1997 actuals, to deal with SF6 leakage.[190]

EPTI has taken prudent steps to improve on its forecast of capital additions for 1999 and 2000. The evidence demonstrates that increases in EPTI's forecast capital expenditures are justified, and that EPTI's forecast is reasonable and prudent and should be approved by the Board.

- the impact of EPTI's reliability centered maintenance project ("RCM") on transmission costs;

EPTI submitted that its RCM program will ensure that its transmission facilities will continue to be effectively maintained at reasonable cost. It indicated that the RCM project would minimize maintenance costs on its aging transmission facilities.[191] Dr. DeSarkar pointed out that EPTI's analysis is conservative, and although net benefits from the program are not seen until 2002, those benefits will continue for the life of the equipment being maintained. Dr. DeSarkar also testified that there are other benefits from RCM, which are not easily quantifiable, such as increased system reliability.

With respect to the level of saving projected for EPTI's RCM program compared to TransAlta RCM program, Dr. DeSarkar stated that it appeared that TransAlta included a number of different items in its analysis which are not part of EPTI's RCM program, but which likely made a contribution to reducing TransAlta's operating costs (i.e. business restructuring and new control centre technology).[192]

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[189] EAL-EPTI-51; Application, Schedules T-17-1999 and 2000
[190] Application, Schedules T-17-1999 and 2000
[191] EAL-EPTI-51
[192] Tr. p.1210

The evidence demonstrates that the capital expenditures associated with EPTI's RCM program are reasonable. EPTI submits that the Board should approve these expenditures as applied-for.

- whether or not EPTI's 1999 and 2000 forecast capital projects should be included in EPTI's Application;

EPTI notes that EAL initially took the position that certain of EPTI's forecast capital projects, which had not been planned and approved by the EAL, should not be included in EPTI's revenue requirement.[193] IPCAA recommended that EPTI's capital additions should be excluded from its proposed revenue requirement until such time as it can be ascertained that the projects are consistent with the TA's expansion plans.[194]

Subsequent to the issuance of the TPG, EPTI advised the Board that its Application was consistent with the guidelines.[195] EAL advised the Board in its letter dated 8 June 1999:[196]

> EAL further advises that it does not require an EPTI witness to speak to the issue of capital projects. Having regard for the direct assignment contemplated by the Transmission Planning Guidelines … EAL does not consider the EPTI forecast of capital additions to be unreasonable.

EPTI submits that the capital projects included in its Application are prudent and are consistent with the TPG. As such, they are properly included in EPTI's Application and should be approved by the Board.

Position of AE

AE submitted that in the context of the Transmission Capital Projects included in its Application, there are two important considerations which should guide the Board's determination of how it will dispose of the Application, as filed. The first of these items is the approved Negotiated Settlement regarding AE's Application:

> …the treatment of transmission capital additions shall also be considered by the Board as part of the Phase I proceedings, including the circumstances and criteria used to determine when and if the TA or the TFO shall be responsible for such projects. The parties will support a perspective decision regarding this matter, as it is recognized that the projects commenced by the TFO under the existing criteria, in good faith should be approved by the Board. Those portions of AE

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193 Exhibit 203, paragraph 63
194 Exhibit 138, V-3, S-3, P-2
195 Exhibit 189
196 Exhibit 192

> Electric's capital additions budget which are not earmarked for projects already underway shall follow the allocation of roles and responsibilities by the Board.

Additionally, AE indicated that the TPG were intended to provide assistance to parties regarding the allocation of roles and responsibilities between the TA and the TFO. The Minister of Resource Development indicated that amendments to the EU Act to implement the guidelines would be proposed at the next time the EU Act is opened in the legislature. Additionally, both AE and EAL indicated that they are prepared to follow the intent and spirit of the guidelines.[197]

While AE's Capital Projects were not subject to any cross-examination and, therefore, may not be a significant issue, AE reiterated its request that all of the requested capital projects for 1999 and 2000 be approved. This approval is consistent with a combination of the operation of Section 25 of the Negotiated Settlement and the TPG, as all of these projects have either been commenced or should be directly assigned to AE in accordance with the guidelines.

In this regard, AE does not agree with the generic approach suggested by the TA during its appearance, wherein it requested that the forecast used by the TFOs be the basis for Board approval, but that part of the approved budget be allocated to the TA. The direct result of such an approach would be extremely unfair to the TFOs. To begin with, this approach was only put forth during the TA examination by the Board and, therefore, parties had no opportunity to understand and test the shortcomings of this new proposal. Additionally, such treatment would create an unbalanced and one-sided mechanism for the consideration of capital projects.

AE notes the submission of the TA, that if a project of the TA was forecast, but did not proceed, it would provide a refund to customers. AE noted, however, that since there is no actual capital spent, there is nothing to refund. What is being dealt with is the possibility that this notional capital would attract a return during the period of time between its initial approval for inclusion in rate base and the consideration of the company's overall rate base in the next GTA. What this one-sided view of the situation fails to recognize is that, if a project is not forecast but must be completed during the interim timeframe between GTAs, the capital is in fact spent but the utility cannot earn a return on such expenditure until the next GTA. That is why AE is prepared to live with its forecasts until updated and changed in the next GTA, regardless of whether or not this is a "win" or "lose" for the company. That is an accepted consequence of the forward test year method of regulation, which would be totally frustrated if the TA's suggestions were adopted. AE submitted that, in the context of the capital projects included in its Application, this suggestion should be rejected.

As indicated, the TPG can provide a basis for future forecasts of Transmission Capital Projects.[198] However, the suggestion of the TA does not provide an acceptable or fair solution.

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[197] Tr. p.6081, p.6187
[198] Tr. p.6116

Board Findings

With respect to TransAlta's northwest Calgary substation site, the Board disagrees with the FIRM Customer's submission that the $800,000 cost for a future substation in the area should be removed from rate base. The Board believes that a substation site in this area may be difficult to obtain in the future. Thus, the cost of retaining the land is low compared to the benefit of having flexibility, if a future need arises. The Board therefore believes that this land should be retained, since it is valuable property which will ultimately represent a benefit to customers.

Furthermore, the Board notes that TransAlta cannot dispose of the land without Board approval. If in the future a third party were assigned the right to construct a substation at this location, the Board could then potentially review an application to transfer the substation site from TransAlta to that party. With respect to the Didsbury parcel of land, the Board agrees with TransAlta that the cost is not significant and therefore should not be removed from rate base.

The Board notes that TransAlta discovered an inconsistency in the filing. At the hearing[199] TransAlta indicated that no construction contribution was forecast for the Nova Joffre project due to the expected amount of standby load. This was incorrect and TransAlta should have forecast a contribution from NOVA equal to the full capital cost of $10 million.[200] Accordingly the Board directs TransAlta, in its refiling, to increase its forecast of 1999 customer contributions by $10 million.

The Board is not persuaded that the capital addition facilities forecast for the Cheviot project will be used or required to be used during the test period. Accordingly, the Board directs TransAlta, in its refiling, to remove the capital additions associated with the Cheviot project from the rate base for the test years.

The following table provides a summary of the proposed capital additions of the TFOs:

TFO Proposed Capital Additions (1999-2000)

$ million	TransAlta		EPTI		AE	
	1999	2000	1999	2000	1999	2000
Forecast	52.5	37.5	6.8	7.7	41.1	18.1
Not Directly Assigned	18.7	29.6	2.7	2.4	5.8	6.7
Directly Assigned	33.8	7.9	4.1	5.3	35.3	11.4
% Not Directly Assigned	35.6%	78.9%	39.7%	31.2%	14.1%	37.0%

The Board recognizes that by including forecast capital requirements for all transmission additions in the TFO revenue requirement, there is a possibility of over-forecasting. The Board notes that if capital addition expenditures are lower than forecast, the TFO's shareholders would

199 Tr. p.2756
200 TransAlta Application Section 3.3 – Transmission CWIP Continuity

receive the benefit. In contrast, if expenditures are higher than forecast, the TFOs incur the loss. The Board notes, however, that since this is true for all forecast costs in a test year, the possibility of over-forecasting should not in and of itself be a reason for removing all capital additions from the TFO's revenue requirements.

With respect to TFO transmission capital additions, the Board agrees with the parties that forecasting is more uncertain than in the past, due to issues related to location, size and timing of new generation and associated transmission facilities. In addition, the Board recognizes that a large number of new transmission projects are a result of Industrial load, as opposed to overall system development load, that makes forecasting of capital additions more difficult. The Board is also concerned about possible increased costs in the post 1999/2000 time frame resulting from duplication of work by both the TFO and TA, to the extent capital projects, including directly assigned projects, are planned and budgeted by the TA.

The Board notes that there are three options available for the development of electric system customer facility additions:

- a customer can build the facility;
- the TA can decide to go to RFP; or
- the TA can directly assign the project to the TFO.

The Board recognizes that if a customer elects not to self-build, projects over the $10 million threshold may automatically go for competitive bid. For projects under $10 million, the Board considers there is uncertainty whether or not a TFO will be directly assigned a project, since the TA reserves the right to go for competitive bid, and transmission customers have an option to construct their own facilities. In this regard, the Board notes from EAL's rebuttal evidence that approximately 35.6 % of TransAlta's, 39.7% of EPTI's, and 14.1% of AE's transmission capital addition expenditures in 1999 have not been directly assigned to the respective TFO. In the year 2000, approximately 78.9% of TransAlta's, 31.2% of EPTI's and 37.0 % of AE's transmission capital addition expenditures have not been directly assigned.

The Board considers that the relatively high percentage of unassigned expenditures, together with the previously mentioned forecasting difficulties, have combined to create a high degree of uncertainty with respect to transmission capital addition forecasting and therefore:

- In order to insure that any under or over forecasting of capital addition expenditures is captured, the Board directs the TFOs to establish a deferral account commencing in the 1999-2000 period.
- At the time of the next GTA, the Board will deal with any variance arising in 1999-2000 to the capital addition forecast, including additional projects and actual costs that were assigned to the TFO.

For the 1999/2000 time frame, the Board will allow the TFOs to include capital maintenance and directly assigned projects in their respective capital addition forecast budgets, except for the Cheviot project noted above.

The Board expects that the TA will reimburse the TFOs for their annual capital related costs and annual O&M capital expenditures (for additional direct assigned projects not included in the approved TFO budget) consistent with revenue requirement parameters and terms approved for the TFO in other sections of this Decision. The costs of the assets assigned to the TFO will be included in the rate base of the TFO at the time of the next GTA for the TFO. The Board expects that the TA and TFO will develop and achieve improved administrative procedures within the scope and intent of the Board's Decision.

Similarly, in the post 1999/2000 timeframe, the Board directs that the TFOs only include capital maintenance and directly assigned projects in their respective capital addition budgets. As well, the budget for remaining system additions, including customer requests that a project be sent out for RFP, should be included in the TA budget. Further, the Board directs AE, EPGI and TransAlta, in their refilings, to clearly identify the amount of capital maintenance included in the refiled capital budget. Further, the Board directs AE, EPGI and TransAlta, in their refilings, to include a definition of capital maintenance projects and to separately identify any major projects so that the Board and interested parties can understand what has been put into this category.

With respect to the concern of some parties that there is double counting of cost, the Board believes that this will be prevented by the introduction of a deferral account. The Board believes that allowing the TFOs to retain their respective capital addition forecasts for capital maintenance and directly assigned projects, subject to a deferral account, will not impact the "level playing field" so as to preclude other parties from bidding, planning and constructing transmission facilities.

(4) Terms and Conditions

(A) General

The Terms and Conditions (T&C) set forth the standards and practices upon which TransAlta, AE and EPTI provide and make available their transmission facilities to the TA, as part of the tariff pursuant to sections 26, 28, 29 of the EU Act.

The TFO, as owner and operator of transmission facilities is responsible for the safe and reliable operation of the facilities, as well as interconnection of the facilities to systems external to the Alberta Electric System. The TFO also has a role in the planning for, and the integration of, transmission facilities in cooperation with the TA.

The TA, as sole provider of transmission system access, is responsible for prudent commercial arrangements for the provision of system access service. This includes the provision of system support service and the management of transmission line losses, as well as the responsibility for

setting reasonable standards and requirements for system access service and system support services. The TA is acknowledged as the Alberta Control Area Operator.[201]
TransAlta, AE and EPTI in each of their Applications requested approval of their respective T&C with the TA. As a result of negotiations with the TA, the parties indicated that they had resolved all issues with the exception of the indemnity provisions, the disclosure of confidential information and dispute resolution mechanism. TransAlta[202], AE[203] and EPTI[204] submitted revised T&C in June 1999. The Board has reviewed the issues that were resolved and approves that portion of the T&C. The Board will deal with the unresolved issues in the following sub-sections:

Sub-section (B)—Indemnity (Section 7)
Sub-section (C)—Disclosure of confidential information (Section 5)
Sub-section (D)—Dispute Resolution (Section 9)

(B) Indemnity

The parties indicated that they had reached agreement that Sections 7.1 (a), (b) and (i) should remain in the T&C as originally filed.[205] Consequently, the only remaining issues with respect to the indemnity provisions, are matters relating to Sections 7.1 (c) to (g), 7.1 (h) and 7.2 of the T&C.

EPTI indicated that it reached agreement with the TA on a revised Section 7.1 (c) to (g), which is outlined in EPTI's discussion later in this section.

With respect to Section 7.2, the parties agreed that the following procedure should be followed:

- The Board would accept the indemnity provisions as proposed by the Utilities in Section 7.2 of their respective Terms and Conditions agreements;
- The Board, and parties, would await the outcome of the DRD initiative to develop a policy with respect to liability and indemnity matters;
- In the event the DRD's policy was considered to be inconsistent with Section 7.2, the Board's decision would include a direction to the Utilities to apply to the Board for any amendment to the Terms and Conditions so that they would be consistent with the policy of DRD;
- The Board, in the EAL application, would approve a clause similar to Section 7.2 of the Utilities' Terms and Conditions;

201 TransAlta –Terms and Conditions Section 2. Acknowledgements
202 Exhibit 181
203 Exhibit 187
204 Exhibit 189
205 Tr. p.5879

- In the absence of any further Government policy or legislation, the Board would accept an application by any interested party to determine the appropriate allocation of risk between the TFO, the TA and customers, and how the cost of risk mitigation should be shared among all parties; and
- Following such proceeding, the Board would make any necessary amendments to the TFO and TA revenue requirements.

The Board invited parties to provide comment, in argument and reply argument, on the appropriate wording of the Board directions required pursuant to the above agreed upon procedure.

Position of TransAlta

TransAlta noted that the Board, after hearing submissions from the other parties, established a process that would allow it to approve the T&C with the indemnity provisions as applied for. EAL has the option to apply to the Board for a similar provision in its application which was before the Board, or in a future application should it be necessary as a result of governmental policy changes. TransAlta supported the process outlined by the Board without change.

TransAlta noted that section 56 of the PUB Act allows the Board to "review, rescind or vary any order or decision made by it," which enables the Board, Applicants or any Interested Party to have the liability and indemnity issues revisited. TransAlta indicated that no specific direction is required to accomplish this. TransAlta noted, however, that the Board may wish to reserve the right to review its decision on liability and indemnity matters contingent on the outcome of the DRD process, and that any applicant or interested party may also avail itself of a section 56 application should the need arise.

With respect to Transmission Administrator Operating Procedures (TAOP), TransAlta noted it does have the opportunity to review and comment on the TAOP as they are developed. Although it can refuse to act upon a TAOP if it contravenes good electric operating practice or any of the other circumstances outlined in Section 7 of the T&C[206], it should not remove all responsibility from EAL for thorough and diligent work, especially in light of EAL's unique position of overseeing the entire transmission system. Therefore, TransAlta requests that the Board approve Section 7 of the T&C as filed.

Position of AE

With respect to the Indemnity Issue, AE's view is that Section 7.1(c) to (g) could be eliminated if in doing so will assist in achieving a consensus on an appropriate indemnity provision.

AE indicated, however, that Section 7.1(h) is required given the TA's insistence that its operating policies or requests be followed by the TFO. In those circumstances, where TFO personnel involved follow the TA's operating policies or requests (even though they may wish to

[206] Exhibit 181

follow a different course of action by utilizing their professional judgment), the TFO cannot be held responsible for any consequences that may arise due to it complying with such operating policies. AE indicated that if the TA wants the authority to dictate what should occur in such circumstances then it must assume the responsibility for the consequences of setting such policies. It would be unfair to bestow upon the TA the authority to demand compliance by the TFO with its operating policies, yet attach to it no responsibility for the TFO following these requirements.

AE provided the following comment on the required Board direction pursuant to the agreed upon procedure:

> For purposes of ATCO Electric's 1999/2000 GTA the Board approves Section 7 of the Transmission Terms and Conditions, as filed. This approval is granted without prejudice to the rights of any party to seek to revisit the subject matters covered by Section 7, pending the outcome of the currently ongoing DRD policy review regarding liability issues for the providers of transmission services. ATCO Electric shall ensure that its Terms and Conditions comply with relevant Government and Board requirements, including any changes which ultimately result from the aforementioned DRD policy review.

Position of EPTI

At the hearing EPTI and EAL indicated that they were considering a revision to clauses 7.1(c) to (g). EPTI indicated that it reached agreement with EAL on these sections.

EPTI provided the following comment on the proposed wording of the required Board direction:

> At the conclusion of the DRD Process underway in relation to TFO and TA liability issues, EPTI will apply to the Board for an amendment of its terms and conditions if there is a material inconsistency between EPTI's terms and conditions then in effect and the determinations that result from the DRD Process. In the event that EPTI does not apply for amendment of its terms and conditions within 45 days of the conclusion of the DRD Process, any interested party may make application for an amendment to EPTI's terms and conditions on the basis that there is a material inconsistency between EPTI's terms and conditions then in effect and the determinations that resulted from the DRD Process. Any amendment made to EPTI's terms and conditions as a result of an application by EPTI or an interested party will be effective at a future date specified by the Board that follows the Board's decision in respect of the amendment.

EPTI noted that the TA takes issue with the inclusion of clause 7.1(h) in the T&C, arguing that the clause is not necessary due to the fact that EPTI has an opportunity to have input into the TAOP and can refuse to comply with them in certain circumstances. The TA also argues that because it does not operate transmission equipment in real time as EPTI does, it should be

relieved from the consequences that may arise from the "real time" implementation of the TAOP by the TFO.

EPTI submitted that the TA should bear the responsibility of ensuring that each TAOP is reasonable and workable, as it has been provided with the authority to develop TAOPs for implementation. Accordingly, EPTI indicated that clause 7.1(h) is fair and reasonable, and should be included in EPTI's T&C.

Position of EAL

EAL submitted that the provisions of Section 7.1(c) through (g) set out a procedure whereby the indemnitor can take charge of any lawsuit against the indemnitee with respect to issues for which the indemnitor may ultimately be liable. EAL notes that TransAlta and AE are neutral as to whether these provisions are removed or condensed and that EPTI is prepared to accept a condensed version, but would prefer to see the concept included in the Terms and Conditions. EAL is not opposed to including the concept as long as it is expressed in clear, concise and condensed language.

With respect to Section 7.1 (h), EAL noted that the TFOs have three opportunities to ensure that implementing a TAOP does not result in third party suffering damage for which the TFO may be held responsible:

- Part 1 of Schedule C of the Terms and Conditions give the TFO the opportunity to comment on draft TAOP.
- After TAOPs are finalized, TFO may refuse to comply with a TAOP, including concerns that may result in damages to third parties.
- In Real Time, the TFO can refuse to implement a TAOP in any circumstances identified in Section 3.1 (f) (Provision of Services).

EAL noted that damages suffered by a third party due to the TFO taking an action that is in compliance with the TAOP, but is nevertheless taken by the TFO in a negligent or perhaps even willfully destructive manner, would still be the responsibility of the TA under Section 7.1(h). To designate the TA, rather than the TFO, as the party financially responsible in these circumstances is totally unreasonable.

The purpose of the consultative process for developing TAOP is to arrive at guidelines that are applicable in as many situations as possible and to provide flexibility for real-time operators to ignore the TAOP where it would be prudent to do so. This process recognizes the fact that it is the real-time operator who is in the best position to recognize a potentially dangerous situation and take the appropriate action. EAL submitted that the TFO should not be permitted to shift the responsibility for the decisions of its operators on to the TA.

EAL also noted that Section 7.1(h) is a significant disincentive for the TA to make any policies at all, which is inconsistent with the statutory duties and functions of the TA. EAL indicated therefore that Section 7.1(h) should be deleted from the T&C.

EAL provided comment with respect to a number of points raised by the FIRM Customers in argument, including:

- The FIRM Customers' argument purports to deal with indemnity issue of Section 7.1 (1). EAL indicated that the issue raised by the FIRM Customers is intended for EAL's Phase I and II which are not before the panel.
- The FIRM Customers recommended inclusion of Section 7.2 pending completion of the DRD process. EAL noted that since the process recommended by the Board was accepted by all parties, the discussion of Section 7.2 in the FIRM Customer's argument is unnecessary.
- The FIRM Customers indicated that EAL oppose Section 7.2 in the Terms and Conditions. EAL indicated that this is incorrect as it has agreed to the Board process, including approval of Section 7.2 pending DRD review.

Position of ENMAX

ENMAX's understanding of the intent of the procedure set out at the hearing was that parties were voluntarily foregoing the opportunity to litigate the liability and indemnity provisions at that time, in exchange for the right to have the issues readdressed if the DRD issued a policy. ENMAX's view is that the Board should make it clear that parties have the "right" to re-litigate the issue if circumstances are changed by the issuance of a DRD policy. ENMAX recommends that the Decision clarify that the issuance of a policy or guideline by the DRD on the matter of liability and indemnity shall be deemed to be grounds to grant a review of those provisions of the Decision on application by any interested party. This does not impact the Board's discretion as to whether or not a variance should be granted.

ENMAX agreed that the proposal put forward at the hearing is a reasonable proposal, which protects the rights of the parties and allows the process to move forward pending receipt of a policy on liability from the DRD.

ENMAX recommended that, subject to the agreed procedure regarding the liability and indemnity provisions, the Board approve the Transmission T&C proposed by TransAlta, AE and EPTI.

ENMAX stated that there is no need for a specific direction in this matter. The Board has the power to review and vary any decision under the provisions of the PUB Act, and the Board's intentions on this issue were clearly set out during the hearing. However, to avoid confusion, ENMAX suggested that it may be helpful for the Board to clearly state its intent in the Decision.

Position of the FIRM Customers

The FIRM Customers provided the following proposed wording for the Board's direction:

> Should the Government of Alberta issue any policy statement, pass any regulation or legislative change that impacts on any of the provisions contained in Article 7 as filed in Exhibits 181, 187 and 189, then the Board's approval of Article 7 shall automatically be subject to review and variance by the Board pursuant to s. 56 of the Public Utilities Board Act (Alberta) or s. 57 of the EUA, as the case may be, on application by EPGI, AE, TAU, EAL or any interested party. In the absence of any such governmental policy statement, regulation or legislative change by September 13, 1999, any interested party is hereby given leave to apply to the Board to review and vary this Order of the Board, as it pertains to Clause 7. The Board will ensure that any review and variance application filed pertaining to Clause 7, will be heard in an expeditious and timely manner with the corresponding Board Order issued on a timely basis.

The FIRM Customers considered that by section 31.2 of the EU Act, EAL has protection for consequential losses caused by its own negligence, or its willful misconduct. The FIRM Customers submit that the legislature never intended this statutory protection to extend indefinitely beyond 20 November 1999, otherwise it would have expressly said so.

The FIRM Customers indicated that EAL's limitation of liability goes beyond that requested by the TFO. EAL requested exemption from claims against it "for any damage, injury or loss of any kind," not just consequential losses. The liability exclusion proposed by EAL is much broader in scope compared to that contained in Section 7.2 being proposed by the TFO. It indicated that it is not "symmetry" and goes well beyond what is required. The FIRM Customers noted that with respect to maintaining symmetry with the TA's T&C, this can be dealt with in EAL's upcoming Phase I and II hearings commencing September 1999.

The FIRM Customers noted that the risk of liability for consequential loss to EAL could only occur:

- after 20 November 1999, provided EAL's statutory exemption is not extended;
- if EAL's Section 14.1 or some variation is not approved;
- if the indemnification Article 7.2 for the TFO is not approved; and
- if EAL somehow caused and is liable in law for consequential loss.

On this last point, the FIRM Customers submitted that the only way the TA would be liable to another person is if the TA owes a duty in law to that person. The TA is a service provider and not an asset manager and operator.[207] The TA does not have any "real-time" responsibilities or obligations.

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[207] Tr. p.6179

The FIRM Customers noted that both TransAlta and AE take the position that their customers, not their shareholders, should bear responsibility for the Utility's negligence causing indirect or consequential loss. The FIRM Customers questioned how management of the Utility is to be held accountable for its negligence or imprudence as we move into a competitive environment.

The FIRM Customers submitted Clauses 7.1 and 7.2 of EPTI, AE and TransAlta's T&C should be approved as filed, noting that the DRD is in the process of conducting a liability review which may at some stage shed further light on this topic.

Position of LE/RD

LE/RD submitted that the alternative agreed to by all parties[208] adequately sets out the intent of the Board in deferring any detailed consideration of this issue.

With respect to Article 7.1(h), LE/RD support the inclusion of such a provision. Such a clause is commonly included in contracts, which obliges a party to carry out certain actions in accordance with the instructions given by the other. In making this submission, LE/RD noted that they do not oppose the TA extracting protective clauses from its customers in order to manage the risk imposed by this type of article. LE/RD also noted that in the absence of such an article, there may be no incentive to do so, thus exposing TFO to uncertain liability from unidentified parties over whom they have no control or perhaps with whom they do not even have any relationship.

Position of IPCAA

IPCAA is of the view that it is essential that the issues relating to the liabilities and responsibilities of all electric Utilities in Alberta be resolved at the earliest opportunity and recommends that the "trigger date" (i.e. the date after which, in the absence of a policy statement, any party could bring the liability and indemnity issues before the Board) be no later than 31 December 1999.[209]

IPCAA suggested the following wording for consideration by the Board:

> The Board directs that if during the test years the Government of Alberta issues a policy statement concerning the matters of liability and indemnity as they relate to [the TFO] and/or the Transmission Administrator, then each of [the TFO] shall, within one month thereafter apply to the Board for approval of any amendments to the terms and conditions of the TFO's Transmission Tariff that may be necessary to ensure that the Transmission Tariff is entirely consistent with such policy statement.

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[208] Tr. p.5755
[209] Tr. p.5884-5887

Position of TCE

TCE did not suggest wording any more precise than that already proposed by the Board. TCE however noted three points:

- First, the criteria for any party to reapply to the Board for reconsideration of the liability issue is not whether the DRD or the Minister issues another policy statement (whether consistent or inconsistent with the present Terms and Conditions). Unless the liability issue is dealt with through legislative amendment, any party dissatisfied with the DRD's policy position should be recognized as having the right to reapply to the Board.
- Second, TCE agreed with IPCAA that if the DRD process does not achieve resolution of this matter within very short order, say, by the beginning of September 1999, the matter should be brought back on the Board's agenda for early resolution through an expedited process.
- Third, TCE submitted that it should be made express that the Board's decision to 'hive off' the liability issues is not a determination or concession by the Board that there must be symmetry between the liability positions of the TFO and the TA.

Board Findings

The Board notes that the outstanding issues with respect to the indemnity provision, involve Sections 7.1 (c) to (g), 7.1 (h) and 7.2 of the T&C.

With respect to Sections 7.1 (c) to (g), the Board notes that EPTI, in reply argument, indicated that it has reached agreement with EAL with respect to revisions to Section 7.1 (c) to (g) of EPTI's T&C. The Board accepts the following revised Sections 7.1(c) to (d) as a replacement to Sections 7.1 (c) to (g) in EPTI's T&C.

> 7.1(c) Subject to Section 7.1(d) hereof, if the Indemnitor delivers to the Indemnitee a written acknowledgement of its unconditional and irrevocable obligation to indemnify the Indemnitee under Section 7.1(a) in respect of:
>
> (i) all of the damages, injuries, losses, liabilities, costs and expenses that may be claimed against, or suffered or incurred by, the Indemnitee in respect of the Claim within 10 Days following the Indemnitor's receipt of the Indemnitee's notice of such Claim and if the existence of such obligation to indemnify is made known by the Indemnitor to the third party claimant (and, if applicable, to the court or other tribunal determining the Claim), the Indemnitee shall make available to the Indemnitor all information in its possession or to which it has access, other than information that has been designated as confidential by the provider of such information, which is or may be relevant to the particular Claim and the Indemnitor shall be entitled, at its option, to take carriage of the

defence of the Claim by its own counsel and, if it elects to do so, the Indemnitee shall cooperate with the Indemnitor to the fullest reasonable extent in the defence, settlement or compromise of the Claim; or

(ii) some, but less than all, of the damages, injuries, losses, liabilities, costs and expenses that may be claimed against, or suffered or incurred by, the Indemnitee in respect of the Claim within 10 Days following the Indemnitor's receipt of the Indemnitee's notice of such Claim and if the Indemnitee is of the opinion that the Indemnitor's interests are not in conflict with its own, the Indemnitee shall make available to the Indemnitor all information in its possession or to which it has access, other than information that has been designated as confidential by the provider of such information, which is or may be relevant to that portion of the Claim in respect of which the Indemnitor has an obligation to indemnify the Indemnitee and consult with the Indemnitor in respect thereof.

The Indemnitee shall not make any admission of the liability regarding, or settle or compromise, that portion of the Claim in respect of which the Indemnitor has acknowledged its obligation to indemnify the Indemnitee without the written consent of the Indemnitor, which consent shall not be unreasonably withheld.

(d) The provisions of Section 7.1(c) hereof shall not apply in respect of any Claim to which the Indemnitor is, or may reasonably be expected to be, a party and where the Indemnitee is asserting legal defences in relation to the Claim that conflict with legal defences being asserted by the Indemnitor.

With respect to TransAlta's and AE's T&C, the Board will eliminate Sections 7.1 (c) to (g) in their entirety, as the parties are unable to agree on a revised language for these sections. However, the Board will consider an application by TransAlta and AE requesting a modification to their respective T&C to include replacement wording for the deleted Sections 7.1(c) to (g).

With respect to Section 7.1(h), the Board agrees with EAL that the TFO should not be permitted to shift the responsibility for the decisions of its operators on to the TA. The Board notes that the TFOs have the opportunity to ensure that the provisions and requirements of agreed upon TAOPs will not result in a third party suffering damage for which the TFO may be held responsible. Accordingly, the Board considers that Section 7.1(h) should be deleted from the T&C.

The Board notes the agreement reached by the parties, at the hearing, that Section 7.2 would be approved as applied for and if necessary further applications with respect to this Section could be made to the Board after the DRD process is complete.

The Board acknowledges that a number of parties, in argument, responded to the proposed wording of a Board direction to accomplish the agreed upon objectives. Accordingly, after reviewing and taking into consideration the comments made by the participants, the Board will use the following steps to deal with the indemnity provision issue:

- The Board accepts the indemnity provision as proposed by the Utilities in Section 7.2 of their respective T&C Agreements;
- The Board, and parties, will allow the DRD initiative to attempt to develop a policy with respect to liability and indemnity matters before litigating this matter;
- The Board notes that if results of the DRD initiative are inconsistent with the Board approved indemnity provisions, section 57 of the EU Act allows the Board to review its order. This provision provides an adequate remedy which can, in the event of discontinuity between the Board's findings and the outcome of the DRD process, enable the Board, the Applicants or any Interested Party to have the liability and indemnity issues revisited on a prospective basis.
- The Board, in the decision resulting from the EAL application, will address the issue in a manner similar to Section 7.2 of the Utilities' T&C.
- In the absence of any further Government policy or legislation, the Board will consider an application by any interested party to determine the appropriate allocation of risk between the TFO, the TA and customers, and how the cost of risk mitigation should be shared among all parties.
- Following such an application, the Board will make any necessary amendments to the TFO and TA revenue requirements.

The Board directs AE, EPTI and TransAlta, in their refilings, to delete Sections 7.1(c) to (g) and Section 7.1(h) from their T&C. The Board directs EPTI, in its refiling, to replace Sections 7.1(c) to (g) with the agreed upon Sections 7.1(c) to (d).

(C) Provision of Information

Position of TransAlta

With respect to the Y2K issue, TransAlta submitted that what it proposes in its T&C is satisfactory, noting that it would meet EAL requirements as it permits release of information when required by law. It indicated that to go further would, in essence give EAL the right to agree with some third party to release information at that third party's request, thus violating TransAlta's confidentiality.

TransAlta noted EAL's argument that the information sharing provisions made available under the T&C as amended and filed, fail to address on a timely basis the possible need for information to be shared with outside agencies.

TransAlta disagreed with EAL's contention that an issue requiring a decision from the Board cannot be resolved expeditiously, especially if, as EAL asserts, such a delay could cause "the WSCC to direct B.C. Hydro to open the intertie."[210]

TransAlta indicated that EAL's proposal is unacceptable, as it restricts TransAlta's ability to manage sensitive information regarding potentially litigious situations. TransAlta noted that the mechanisms provided by it in its Terms and Conditions are reasonable and provide effective measures for EAL to address its concerns. Accordingly, TransAlta requested the Board to approve the information sharing provisions as amended.

Position of EPTI

EPTI noted that Section 1(i) of Schedule A of the T&C provides, in part, that the TA shall not disclose to any external agency Y2K information received from EPTI without its prior written approval and such disclosure shall be subject to any reasonable conditions imposed by EPTI.

EPTI indicated that the sensitive Y2K information should be kept confidential.[211] Disclosure of certain information would prejudice EPTI's legal position in respect to claims that may arise relating to Y2K readiness issues. It is not in the interest of those who pay for the use of EPTI's facilities, nor is it in EPTI's interest, for its legal position to be prejudiced in relation to such claims.

EPTI stated that Section 5(f) provides for a dispute mechanism if parties cannot agree on the provision of information or the need for confidentiality under Section 5. If the TA makes a request under Section 5 and EPTI refuses to provide written approval allowing the TA to disclose the information, then the TA would have the opportunity to apply to the Board for resolution. Accordingly, EPTI believed that Section 1(i) of Schedule A, along with Section 5(f) of the Terms and Conditions, constitutes a fair, reasonable and balanced approach to the issue of dealing with confidential and commercially sensitive Y2K information.

EPTI submitted that the rationale for providing a mechanism by which EPTI can maintain confidentiality of Y2K information clearly outweighs the TA's arguments for having no restrictions on its ability to disseminate Y2K information. This is particularly so, given:

- the ability of the TA to have disputes resolved by the Board;
- the admittedly slim chance that the TA may be required by the Western Systems Coordinating Council (WSCC) to actually disclose confidential Y2K information; and

[210] EAL Argument, p.35
[211] Tr. p.1194

- the TA's acknowledgement that the "TFO have been co-operating fully to assist EAL in the discharge" of its obligations to the WSCC respecting Y2K contingency information.

The Terms and Conditions as written strike an appropriate balance in the circumstances. There is clearly no reasonable basis for concluding that a resolution by the Board may not be sufficiently timely for the TA's purposes. EPTI submitted that the TA has failed to demonstrate that the Terms and Conditions as written are unreasonable, and accordingly the Board should reject the TA's suggested changes and the clause should be included in the Terms and Conditions.

Position of AE

AE noted that the measures taken to ensure Y2K readiness involved an unprecedented degree of cooperation and information sharing among a variety of parties. It noted that much of the information was received on a confidential basis and AE is not permitted to share this information without the permission of the providing party. As well, the other parties agreed to treat the information as confidential.

AE considered that there is no need for the Board to give the TA the authority to disclose this information without the requirement of recourse to the Board, should an agreement between the parties not be reached. AE was confident that this matter will not require further Board involvement. However, AE considered that the TA cannot be given a unilateral right to decide whether it can disclose information that the TFO considers confidential.

With respect to providing Y2K information, AE indicated that it intends to provide the TA with the information necessary for it to fulfill its obligation.[212] As well, it noted that that all parties are working together in cooperation to ensure that Y2K problems are not encountered, and if they do arise, contingency plans are in place to address such unforeseen events.[213] Nonetheless, AE noted that the disclosure of Y2K information is an extremely sensitive commercial matter. It submitted that the potential consequences associated with a Y2K problem cannot be quantified at this point in time, and therefore it is important that the TFO maintain confidentiality in certain circumstances.

AE indicated that it is not requesting that it have the ultimate right to refuse to disclose information to the TA. However, it does believe that in circumstances where it claims confidentiality for commercial or competitive reasons, the TA must follow the normal process, which involves recourse to the Board, should the parties not be able to resolve the dispute themselves. AE submitted that the TA should not have an automatic right of disclosure.

AE noted that it could not control the terms of agreement between the TA and a third party, noting that it is not a party to these agreements. AE submitted that the TA could come back to the TFO requesting disclosure of information, because it is obliged to do so under its agreement

[212] Tr. p.6103
[213] Tr. p.6212-6213

with such third party. AE stated that the TFO must have the ability to contest the disclosure of information if it considers that such disclosure will operate to its commercial or competitive prejudice. Furthermore, due to the fact that some agencies such as the WSCC now have independent marketers as members and as potential competitors, AE is very reluctant to share certain commercially sensitive information with this group.

AE suggested that the concerns of EAL, regarding an inability to share with entities such as the WSCC, can be resolved by telling EAL up front that it will have to go through the Board's process prior to it being able to disclose certain information. This will enable EAL to reflect such a requirement in its agreement with the WSCC or other third parties, and these entities will be able to condition their expectations accordingly, as they will clearly know the position of the Board on the matter.

AE requested that the Board approve Section 5 as amended.

Position of EAL

EAL is concerned with respect to the information sharing provisions in the T&C. The issue is one of timing and the TA's ability to meet its obligations to an External Agency, such as the WSCC. As Alberta control area authority, EAL may be required to provide the WSCC, Y2K information that it receives from a TFO. However, as a result of the Terms and Conditions, EAL may be prevented from responding to a request from the WSCC.

EAL noted that its obligations to the WSCC include filing a Y2K contingency plan for interconnections with other jurisdictions. The TFOs have been co-operating fully to assist EAL in the discharge of this function. If the contingency plan raises any concerns for the WSCC, EAL may be asked to provide additional information. To meet this obligation the TA may require information from one or more of the TFO.

EAL indicated that if the parties cannot agree whether the information should be kept confidential, Section 5(f) contemplates that the Board would resolve the dispute. If EAL receives a request for information from an External Agency, regardless of whether that request pertains to Y2K or general information, the requirement that the Board resolve the dispute may prevent EAL from meeting its commitments in a timely fashion. These problems are of a more pressing nature in the area of Y2K. Unfortunately, if an External Agency, like the WSCC, requests Y2K information, the TA may not have the luxury of time to follow the process contemplated by the T&C. EAL submitted that it is necessary that the TA be able to respond quickly in order to avoid any potential adverse impacts including the potential, for the WSCC to direct BC Hydro to open the intertie. To do otherwise would not be in the interests of the security and reliability of the AIES. EAL believes that the contingency of an impasse between the TA and the TFO must be addressed now so that it does not create undue delay or adverse impacts in the future.

EAL therefore recommends that Section 5(e)(vi) be amended to specify that information required by an External Agency from the TA is excluded from the confidentiality provisions of the T&C. As well it suggested that schedule A, Section 1(i) be deleted.

A revised Section 5(e)(vi) would read as follows:

> (vi) must be disclosed by ESBI Alberta Ltd. to the Board, the Power Pool Council, the Power Pool Administrator or the System Controller in order to perform its duties and functions as TA or to the WSCC in order to fulfil its obligations as control area manager or member of the WSCC.

Position of the FIRM Customers

The FIRM Customers noted that if the Indemnity provision under Section 7 is approved, then the Y2K information should be released to the WSCC.

The FIRM Customers noted that one of EAL's concerns is the provision of Y2K information from the TFO to the WSCC in a timely fashion. The FIRM Customers questioned why EAL cannot ask the WSCC if it will require such information in advance. If the WSCC does not require the information, then the issue is moot.

The FIRM Customers submitted if the WSCC requires more detail of the Y2K plans of the TFO, such information should be provided. It is clearly in the public's best interest.

Board Findings

The Board, in considering the Y2K provision of information issue, recognizes both the concern of the TFO in being required to provide confidential information to EAL and EAL's concern that a third party such as the WSCC will request confidential information.

The Board notes the TA's acknowledgment that the "TFOs have been co-operating fully to assist EAL in the discharge of its obligation to the WSCC respecting Contingency Information."[214] The Board is of the view that there was insufficient evidence presented at the hearing for the Board to conclude that confidential material would be required to be supplied by EAL to a third party. Nevertheless if a dispute were to arise, the Board considers that it has the authority to deal with this issue. Therefore the Board approves Section 5 of the T&C as applied for.

The Board expects that all parties will continue to cooperate to avoid any potential conflict with the WSCC or other third parties, so as to protect the public interest. However, if the Board is requested to resolve an issue under Section 5, the Board will consider the matter a priority and deal with it expeditiously. If a dispute does arise, the Board considers that either the TFO or EAL could request that the issue be resolved by the Board.

[214] TA Argument

(D) Dispute Resolution

At the hearing the Board requested that parties address in argument any need to change the arbitration Section of the T&Cs.

TransAlta, AE, EPTI and EAL supported the arbitration provisions of the T&Cs of service. TransAlta and AE, however, expressed the view that third parties, and the Board, would not be involved in, and would not be notified of issues going to arbitration under the T&Cs. EAL, on the other hand while taking the position that it was not appropriate for third parties to be part of arbitration, is prepared to notify interested parties that arbitration is taking place, and the results of the arbitration. TransAlta, AE, EPTI and EAL also noted that the Board retains the ultimate jurisdiction over the T&Cs. The FIRM Customers raised the concern that the proposed arbitration provisions would be an unauthorized delegation of the Board's powers.

Position of TransAlta

TransAlta submitted that the Board should retain overall jurisdiction over the consideration and approval of the T&Cs and at any time the Board may reconsider any aspect of the T&Cs and change them on a prospective basis, if determined appropriate. As such, should the Board approve this provision, as requested by both the TFOs and the TA, disputes which fall within the scope of the section would be governed by Arbitration and would not come before the Board. Specific decisions of an arbitrator(s), appointed under this section, would not be appealable to the Board. In TransAlta's view, the purpose of the dispute resolution mechanism is to avoid burdening the Board with such matters. Only those sections of the T&Cs that specifically provide for recourse to the Board would come before the Board.

TransAlta stated that third parties would not be involved in matters sent to the dispute resolution process under Section 9. Only if the dispute resolution mechanism led to a change in the T&Cs, which would require Board approval, would either the Board or third parties be given notice of or become involved in such matters.

TransAlta noted TCE's argument that "the arbitration provisions in the T&Cs should not be approved in any form." stating that this would amount to "improper subdelegation of the Board's authority under the *Electric Utilities Act.*" TransAlta disagreed with TCE, noting that it is proper for disputes, arising under T&Cs approved by the Board, to be submitted to arbitration. TransAlta noted that arbitration does not oust the jurisdiction of the Board any more than a provision requiring that disputes under the T&Cs be submitted to the Court of Queen's Bench of Alberta. TransAlta noted that the Courts routinely uphold arbitration clauses and reject any suggestion that they usurp the role and jurisdiction of the Courts.

TransAlta contended that the same argument applies to the Board with respect to the T&Cs it has been asked to approve. The simple answer to TCE's concern is that the inclusion of an arbitration provision does not constitute an improper "delegation" in law. TCE cites no legal authority to the contrary and it is submitted that there is none. For there to be a delegation there

would have to be language that would enable arbitrators to change the provisions of the T&Cs rather than, as is the case here, arbitrate disputes that have arisen under the Board-approved wording of those provisions.

TransAlta requested that the Board approve Section 9 of its T&Cs as applied for.

Position of EPTI

EPTI indicated that the Board should retain overall jurisdiction respecting approval and amendment of EPTI's T&Cs. It submitted that the Board may at any time consider an application by an interested party for amendment of the T&Cs on a go-forward basis. If the Board approved EPTI's T&Cs, Section 9 would remain in effect until such time as the Board approved an amendment. EPTI contended that any disputes between the parties that fall within the scope of Section 9 would be dealt with through arbitration. EPTI submitted that disputes would not come to the Board in the first instance or "on appeal" following arbitration. EPTI noted that, as is generally the case with any dispute that involves a utility and one of its customers, the resolution of disputes through arbitration would be a matter between EPTI and the TA that would not involve other parties. EPTI indicated however that disputes that are specifically referred to the Board in the T&Cs would come to the Board for resolution and not to arbitration.

EPTI noted that many parties support the inclusion of the arbitration provisions, including AE, TransAlta and LE/RD.

EPTI noted that TCE is the only party to argue that clause 9 should not be included in the T&Cs. The basis for TCE's position is that the provision constitutes an illegal delegation of authority from the Board to another decision-making body. EPTI indicated that TCE's argument is clearly without merit noting that the arbitration provision sets out a procedure for resolving disputes which arise with respect to the T&Cs that apply to the service provided by the TFO except for certain matters that are excluded.

EPTI argued that the Board does not have inherent jurisdiction as a court does and its jurisdiction is established in its enabling legislation. Neither the EU Act nor the PUB Act expressly grant to the Board the authority to adjudicate disputes between a TFO and a customer in relation to breaches or alleged breaches of a term or condition of an approved tariff or to grant to the TFO or a customer a remedy, such as damages, for such a breach. Section 57(2) of the EU Act provides that a person affected by any order approving a tariff may ask the Board to review the order if the owner of the electric utility has breached in a material manner a term or condition of the tariff.

Without addressing the question of whether the Board has jurisdiction to adjudicate on or award damages in respect of breaches of a tariff, the Board clearly does not have exclusive jurisdiction to do so. EPTI indicated that if a customer of an electric utility fails to make a payment to the owner under a tariff, in accordance with T&Cs approved by the Board, the owner would be

entitled to sue the customer and seek a judgement from a court for damages in relation to that breach. The owner would not be limited to making an application to the Board.

EPTI submitted that arbitration is a form of adjudication. The jurisdiction of an arbitrator to resolve a dispute arising from the contract between the parties to submit the dispute to arbitration. As a result, the arbitration provision in the T&Cs does not involve a delegation by the Board of any powers it may have to adjudicate on disputes under an approved tariff or grant remedies for a breach of the tariff. The arbitration provision in the T&Cs deals with the resolution by an independent arbitrator of disputes arising with respect to the performance or non-performance of those approved T&Cs. It does not purport to give the arbitrator jurisdiction to change the approved T&Cs. Under the EU Act, any change to the T&Cs would have to be approved by the Board before it could be put into effect.

EPTI therefore submitted that the Board should approve Section 9 as proposed in the applied-for T&Cs.

Position of AE

AE is of the view that the Board has and retains overall jurisdiction over the consideration and approval of the T&Cs. As such, the Board can, at any time reconsider any aspect of the T&Cs it considers appropriate and change the T&Cs on a prospective basis, if the Board determines this action desirable. AE stated that should the Board approve this provision, as requested by both the TFOs and the TA, disputes, which fall within the scope of the section, would be governed by arbitration and would not come before the Board in any respect. As such, specific decisions of an arbitrator(s) appointed under this section would not be appealable to the Board.

AE believed that the purpose of the alternate dispute resolution mechanism is to avoid burdening the Board with such matters. Only those sections of the T&Cs, which specifically provide for recourse to the Board, would result in matters coming before the Board.

Furthermore, AE submitted that it was not anticipated that third parties would be involved in any matter sent to the resolution under Section 9. Only if the dispute resolution led to a potential change in the T&Cs, which would require Board approval, would either the Board or third parties be given notice of or become involved in such matters. AE indicated that whether or not certain information has to be provided by either party or, if so, subject to confidentiality, is a matter solely for the parties. AE submitted that this process is consistent with the general operation of an alternate dispute resolution process and should be approved by the Board. The process is fair to all parties and ensures participation in any situation that could result in a potential change to the approved T&Cs.

AE noted that the FIRM Customers made submissions with respect to the proposed dispute resolution mechanism contained in the T&Cs. AE does not agree that accepting this provision, as proposed, constitutes improper delegation. Should the Board decide that it could not permit the delegation of dispute matters to an arbitrator, AE requested that the provision for initial recourse

to an arbitrator, as currently submitted, be retained. The Board's authority could be preserved by simply adding a caveat that all decisions of the arbitrator could be appealed to the Board, by either party or at the behest of the Board itself. Given the nature of many issues which are likely to arise in the context of the administration of the T&Cs this would be a very beneficial provision.

Position of EAL

EAL notes that Section 9 of the T&Cs sets out a process for addressing disputes. EAL submitted that the dispute initially requires resolution by the TA and TFO which reduces the potential for arbitration. It is expected that most differences of opinion regarding the T&Cs will be resolved in this way. Only if this initial step is not fruitful do the provisions dealing with formal arbitration under the *Arbitration Act* apply.

EAL indicated that formal arbitration under the *Arbitration Act* is intended to provide certainty of process and to introduce efficiency and cost effectiveness to dispute resolution where the parties have been unable to agree. Reliance on arbitration under the *Arbitration Act* provides the parties with a binding dispute resolution mechanism consistent with the EU Act, which encourages minimization of the cost of regulation where regulation is necessary.
EAL submitted that the arbitration provisions are not intended to usurp the authority of the Board. The Board would continue to have ultimate authority over the T&Cs. Section 9 contemplates that the arbitration provisions of the T&Cs can be bypassed and a dispute referred directly to the Board where system security or irreparable harm or significant injury to a party is involved. In addition, EAL noted that Section 9 of the T&Cs is not intended to override the ability of any interested party to seek a review of the T&Cs by the Board. Section 9 recognizes that where it is reasonable to do so, potential disputes that may arise between the TA and a TFO should be resolved without burdening the Board.

Furthermore, EAL submitted that the arbitration provision was not intended to keep stakeholders in the dark. EAL does not intend that disputes that go to arbitration should be resolved in secret and has no objection to stakeholders being advised once a dispute reaches the stage of arbitration. Nor would EAL object to providing its stakeholders with notice of any decision by an arbitrator. However, it is not intended that stakeholders would be parties in arbitration under Section 9 of the T&Cs. Otherwise, the efficiencies and cost savings would not materialize. EAL recommended that Section 9 of the T&Cs not be modified in any way.

Position of the FIRM Customers

The FIRM Customers noted that there are two issues with respect to Section 9 - Dispute Resolution. The first issue involves determining what disputes under the T&Cs are to be referred to arbitration. The other issue concerns the possible impact the appointment of an arbitrator would have on the Board's jurisdiction to deal with disputes regarding the T&Cs.

The FIRM Customers believe that a dispute would be brought before the Board only in those cases where:

- The TA believes the delay in resolving any dispute in accordance with Section 9 may pose a real and imminent threat to System Security; or
- Either party believes the delay in resolving any dispute in accordance with Section 9 may result in such Party suffering irreparable harm or significant injury.

The FIRM Customers noted that the proposed dispute resolution provisions under clause 9 envisage the appointment of an arbitrator at the insistence of either the TFO or TA. The arbitrator is able to usurp the Board's decision-making function in dealing with disputes under the T&Cs. The type of arbitrator proposed is not restricted to an "official or employee of the EUB or the PUB."

The FIRM Customers submitted that the Board would not have jurisdiction to intervene once an arbitrator is appointed under Section 9. It also noted that it is possible that an arbitrator's decision may not be consistent with well-established Board principles. As well, decisions made by the arbitrator regarding payment for "additional services" as contemplated under the T&Cs, could impact rates set by the Board.

If the Board accepts the FIRM Customers' submissions, then Section 9 must be revamped. The first two paragraphs could remain, but the third and fourth paragraphs would be deleted. In their place, the FIRM Customers submitted that consideration could be given to inserting the following clause:

> Where such dispute remains unresolved, then either the TFO or the TA may apply to the Board on notice to all interested parties for an order to resolve such dispute.

The FIRM Customers noted that the TFOs and the TA objective is to provide a cost effective, expedient and efficient method to resolve disputes arising under the T&Cs and minimize the workload of the Board. However, the FIRM Customers argued that the TFOs and the TA are inviting the Board to abdicate its jurisdiction.

As an alternative to the TFO's and TA's approach, the FIRM Customers suggested that the Board under Section 12 of the *Alberta Energy and Utilities Board Act* (AEUB Act) approve the selection of the arbitrator. In such a case, it would be necessary to specify the provisions of the *Arbitration Act* that do not apply.

While the FIRM Customers do not want to see the Board unduly burdened with additional work, it is concerned with respect to the potential abdication of decision making authority and loss of jurisdiction of the Board. EAL argued that the Arbitration provisions are not intended to usurp the authority of the Board. Although the TA may not intend for this to happen, the application of the *Arbitration Act* would prevent the Board from reviewing the arbitrator's decision.

The FIRM Customers indicated that another concern is how the costs of the arbitration tribunal would be paid and who would bear these costs. As a decision making tribunal, the Board does not directly charge the parties for its services, however an arbitration tribunal would.

Under the current section, there is neither indication as to who will decide if third party stakeholders should be involved, nor the criteria for their involvement. In the FIRM Customers submission, if a matter is serious enough to require arbitration, potentially affected stakeholders ought to be given notice so they can decide if their participation is warranted. Where a matter is considered "confidential," disclosure could still be achieved without divulging the specific, confidential information in question. Simply precluding participation by interested stakeholders in the interests of efficiency and economy is contrary to the principles of procedural fairness and natural justice.

The FIRM Customers submitted that it is within the Board's power and mandate to determine what notification, if any is required to be given to interested parties. In "contentious matters", section 43(4) of the PUB Act gives the Board the power to require notice to be given "as it considers requisite." Section 50 of the PUB Act enables the Board to make orders without adequate or any notice to interested parties, providing there is proper justification.

In summary, the FIRM Customers submitted the Board does not have the legislative jurisdiction to delegate its decision making duties to an arbitrator pursuant to the arbitration provisions contained in Section 9. Section 12 of the AEUB Act expressly indicates the Board's right of delegation relates only to these individuals. If the current proposal were modified to incorporate this type of arbitral delegation, it would be workable and within the legislative parameters.

Positions of LE/RD

LE/RD noted that there are numerous disputes of a contractual nature that have little if any public impact and which ought not to require the attention of a full regulatory process. LE/RD indicated that the easiest way to balance public concerns with ease of determination is to have the parties notify the Board if such dispute is proceeding to arbitration, and let the Board decide whether any further public notification is required. LE/RD is in favour of any provision that generally reduces regulatory burden and expense.

With respect to the specific provisions, LE/RD has no comment other than to note that the provisions proposed do not differ significantly from many commercial dispute resolution clauses, and LE/RD does not see much difficulty with them.

Position of TCE

TCE submitted that the arbitration provisions in the T&Cs should not be approved. In TCE's submission, approval of the arbitration provisions as presently drafted would amount to improper subdelegation of the Board's authority under the EU Act.

TCE supported EAL's interest in transparency and agreed that Section 58 of the EU Act gives Intervenors the right to complain concerning anything which is unfair, prejudicial or impacts them negatively. However, TCE submitted that the issue of whether arbitration is undertaken by EAL and the TFOs in "secret" or not is not the main issue. The main issue is whether the Board may properly delegate any matters within the scope of its jurisdiction to an arbitrator, and, if so, whether the scope of the matters which the T&Cs provide for reference to an arbitrator are limited to those matters which may be delegated.

TCE submitted that the T&Cs allow the referral to an arbitrator of all substantive matters dealt with in the T&Cs. The scope of the disputes referred to an arbitrator include disputes which may arise under Section 3 of the T&Cs, which addresses the ability of the TFOs to interrupt or curtail the provision of transmission services. TCE submits that these matters are under the exclusive jurisdiction of the Board.

TCE noted that the Board has been given broad authority under the AEUB Act and the PUB Act, and in the context of the present applications, has specific powers to approve or reject, in whole or in part, the Applicants' tariffs under the EU Act. Under the AEUB Act, the Chairman of the Board may designate any three or more members of the Board to sit as a division of the Board and may direct that division to conduct any hearing, inquiry, investigation or other proceeding that the Board would conduct under the AEUB Act or any other enactment.

TCE noted under Section 36 of the PUB Act, the Board may appoint or direct a person to make an inquiry or report on any application or dispute before the Board which the Board has jurisdiction. While Section 36 permits the Board to appoint or direct a person to make an inquiry and to make a report to the Board, the report is for the assistance of the Board. It is the Board that renders the final decision, not the party appointed.

TCE submitted that the arbitration provisions in the T&Cs should not be approved. There is no reason for the arbitration provisions, and, in TCE's submission; approval of the arbitration provisions as presently drafted would amount to improper subdelegation of the Board's authority under the EU Act.

Position of ENMAX

In ENMAX's view, the concerns raised by the FIRM Customers and TCE regarding unauthorized delegation are unfounded. There are many areas in the T&Cs where the TA, the TFO, and other interested parties could have different interpretations of the meaning or requirements of the T&Cs. If the TFO and the TA discuss and agree on a particular interpretation, other interested parties, and the Board, may never know that the discussion even took place unless an interested party is affected. Similarly, if the TA and the TFO disagree over a provision, they are free to resolve the dispute by negotiation, compromise or mediation. Once again, other parties, and the Board, may never even know there was a dispute. In such circumstances, where the parties settle their differences by negotiation, no one would suggest that this would be an improper delegation of the Board's authority.

If the TA and the TFO can agree to settle issues by negotiation, ENMAX does not see a concern with settling the issues by arbitration. As noted by TransAlta, EPTI, AE and EAL, the Board retains the ultimate authority over the T&Cs. Any interested party adversely and unduly affected by the interpretation or application of the T&Cs, whether from negotiation, compromise or arbitration would be able to apply to the Board for relief.

ENMAX is of the view that the Board's Decision in this matter needs to recognize that the current administration of the transmission system is in the early stages of its evolution and some flexibility is in order. The TFOs and the TA have proposed the arbitration provisions as an attempt to streamline the dispute resolution process and ease the "regulatory burden." These attempts will not be successful if the parties cannot work together in a cooperative manner. Developing cooperation will be difficult if the TFO and the TA are required to take every unresolved dispute to litigation before the Board. Consequently, ENMAX suggested it is appropriate to approve the proposed arbitration provisions of the T&Cs, but the Board should recognize that further action may be necessary if it appears that the provisions are not working properly, or that interested parties appear to be unduly affected.

However, ENMAX is concerned that arbitration would be "private" and that interested parties would not be notified. Given the likelihood that only serious disputes would be taken to arbitration, ENMAX agreed that interested parties should, at least, be notified of arbitration and that interested parties, and the Board, be notified of the outcome of an arbitration. ENMAX submitted that the Board should either direct an amendment to the T&Cs to require notification, or, at least, clearly express the view in the Decision that the Board expects notification would be provided.

Board Findings

The Board in reviewing the arbitration issue notes the various positions put forward by the parties. TransAlta, AE, EPTI and EAL supported the proposed arbitration provisions.

The FIRM Customers raised concerns that the arbitration process would be an unauthorized delegation of the Board's powers and TCE argued that the Board should not approve the arbitration provision of the T&Cs. LE/RD and ENMAX, although in support of the arbitration process, indicated that other parties, besides those affected, should be notified if a dispute goes to arbitration.

The Board notes the FIRM Customers' concerns that the Board would not have jurisdiction to intervene once an arbitrator is appointed under Section 9 of the T&Cs.

The FIRM Customers, therefore, suggested the following clause be included in the T&Cs:

> Where such dispute remains unresolved, then either the TFO or the TA may apply to the Board on notice to all interested parties for an order to resolve such dispute.

Further to this issue, the Board notes that in argument, AE indicated that:

> The Board's authority could be preserved by simply adding a caveat that all decisions of the arbitrator could be appealed to the Board, by either party or at its behest of the Board itself. Given the nature of many issues which are likely to arise in the context of the administration of the T&Cs this would be a very beneficial provision for this agreement.

The Board recognizes that arbitration clauses are often used in commercial contracts. However, in many cases, the types of issues or circumstances that will go to arbitration are clearly defined in the contract. In most business situations, only the parties to the agreement would be directly affected by the decisions of the arbitrator.

The Board supports alternative dispute resolution and applauds efforts of parties to reconcile difficulties without coming to the Board unnecessarily. The Board recognizes that parties regulated by the Board will often resolve their conflicts by use of an arbitration clause.

The Board notes that the arbitration provision in the T&Cs deals with the resolution by an independent arbitrator of disputes arising with respect to the performance or non-performance of the approved T&Cs. The arbitration provision does not purport to give the arbitrator jurisdiction to change the approved T&Cs. Under the EU Act, any change to the T&Cs would have to be approved by the Board before it could be put into effect.

Accordingly, the Board approves the Section 9 arbitration provision of the T&Cs and the Board directs the inclusion of the following provisions:

- The TFO is required to advise the Board of any matter going to arbitration within 30 days of the matter being referred to arbitration. In addition, the TFO shall advise the Board of the results of arbitration within 30 days of the Arbitrator's decision.
- At the same time, the TFO shall provide the Board with a list of potentially affected parties.
- Any interested party adversely and unduly affected by the interpretation or application of the T&Cs, whether from a negotiation, compromise or arbitration, is entitled to make an application to the Board requesting a clarification or change to the T&Cs in the first instance.

The Board is prepared to accept minor changes to the above wording, in the TFO's refilings, if agreed to by the TFOs and the TA.

The Board also has the following observations:

- If the TFO and TA wish to limit the scope of matters going to arbitration, either could apply for an amendment to Section 9.
- Similarly, the TFO and the TA could voluntarily decide to submit specific issues to arbitration and could voluntarily bind themselves not to initiate an application to the Board.
- The TFO and TA may voluntarily choose to advise potentially affected parties of any issue going to arbitration or any results of arbitration.
- The Board will decide if additional affected third parties should be notified of the issue going to arbitration or of the results of arbitration. The Board will expect recommendations by the TFO on the appropriate notification to potentially affected parties.
- The Board will monitor the proposed arbitration provisions of the T&Cs, and take further action as may be necessary to ensure the provisions are working properly and that the rights of interested parties are not unduly affected.

The Board is not prepared to limit the rights of legitimately affected parties coming before the Board. The Board can review any and all items in the T&Cs and is not prepared to delegate or abdicate its responsibilities.

The Board considers that its Decision in this matter will avoid uncertainty for both current and future participants in the restructured industry by demonstrating that the rights of all parties will be protected in the restructured electrical industry by having recourse to the Board if necessary.

(5) Incentive Regulation

As set out in section 51(1)(b) of the EU Act, when considering whether to approve a tariff that is effective after 31 December 1995, the Board shall ensure that the tariff provides for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the electric utility and customers.

Incentive Regulation is intended to minimize cost regulation of the Alberta Electric Industry, and to ensure tariffs provide incentives for efficiencies. Other benefits include the sharing of savings amongst the TFOs and customers of the TA while maintaining an acceptable level of performance as well as allowing TFOs to retain a portion of the savings for meeting expectations.

Position of TransAlta

TransAlta submitted that prospective test year regulation in Alberta has been effective in providing incentives for efficiencies and that the resulting cost savings and other benefits have been equitably shared between TransAlta and its customers. At the hearing TransAlta indicated:

> The benefit to the customer is in the regulatory structure we have is if we work on a prospective basis, then the productivity gains we make in any particular test year are reflected in the future test years, and the customers enjoy those benefits as a reduction of rates in the future test years compared to what they would have been had we not made improvements.
>
> To some extent there are some other ways that benefits show up. For instance, these days if generation makes an improvement in their output, you would expect that to show up in a lower pool price overall, and those customers that are on a pool price flow-through rate would see a benefit in that year.[215]

TransAlta submitted that its proposed tariffs are in full compliance with the EU Act and do provide appropriate and effective incentives for efficiency.

Furthermore, TransAlta stated that the introduction of deferral accounts for the 1999 and 2000 test years, as proposed by various parties, including EAL, would act to defeat the requirement of the EU Act to provide incentives for efficiencies. TransAlta submitted that deferral accounts not only reduce incentives for efficiencies, but also in some instances actually provide incentives to pursue inefficient behavior.

TransAlta indicated that there is no evidence that any particular form of tariff design would be better than the use of prospective test periods without deferral accounts. Accordingly, TransAlta submitted that the Board has no basis on which to direct TransAlta to pursue any specific alternative form of tariff design.

Position of EPTI

EPTI noted that the TA requested that the Board indicate to interested parties that it expects Incentive Regulation to be pursued with a view to implementation by a specific date. The TA suggested that an Incentive Regulation scheme should be implemented on 1 January 2001.

EPTI is open to alternative Incentive Regulation schemes,[216] however implementation should not proceed in an unreasonably short time period. The electrical industry in Alberta is currently going through a number of significant changes which will continue over the next two years, including the auction and implementation of the PPAs, the shift to retail competition, significant changes in transmission pricing and the finalization and implementation of the TPG.

While EPTI agreed that it would be helpful to have some form of "date certainty" to assist in moving the process of developing an Incentive Regulation scheme forward, an implementation date of 1 January 2001 is unreasonable. Further, EPTI is of the view that the appropriate time to

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[215] Tr. p.2022-2023
[216] EAL-EPTI-50

commence discussions with respect to Incentive Regulation would be following the issuing of the Board's Decision in EAL's upcoming Tariff proceeding, given the complexity and significant changes being requested in the TA's Tariff Application.

Position of IPPSA/SPPA

IPPSA/SPPA submitted that the TA's proposal is consistent with the development of an Incentive Regulation scheme for "wires." If the TA approves a direct assignment, then the "public interest" criteria could be met for the period of time the Incentive Regulation is in place. The TFO would simply adjust the rate charged to the TA to reflect those capital additions and related costs assigned to the TFO. This approach would simplify Incentive Regulations and eliminate concerns parties may have over capital additions that vary significantly from some forecast.[217] IPPSA/SPPA supported EAL's request that the Board provide guidance on the timetable for Incentive Regulation.

Position of EAL

As part of its written evidence, EAL filed a report on Incentive Regulation prepared by the National Economic Research Associates (NERA).[218] EAL requested information from the three Utilities on the issue of Incentive Regulation. It is clear from the Utility responses that they had not sufficiently progressed their thinking on Incentive Regulation for transmission to make discussion of the issue in this proceeding worthwhile. On that basis, EAL indicated to the Board and interested parties that it would not pursue the issues reviewed in the NERA report at this proceeding.

EAL believed that stakeholders would prefer to have Incentive Regulation of transmission tariffs proceed within a reasonable time. EAL indicated that it would be in the best interests of all parties if the Board were to provide some guidance with respect to a timetable for consideration of Incentive Regulation for transmission.

EAL is concerned that without such guidance from the Board, it would be difficult to initiate a timely implementation of Incentive Regulation. EAL set out a potential timetable requesting:

> The Board direct the TFOs to pursue, in conjunction with the TA and stakeholders, an Incentive Regulation scheme for the wires costs for implementation on 1 January 2001. EAL further recommends that the Board direct specific milestones in the process.[219]

EAL submitted that in the absence of the views of interested parties, it is unlikely that the Board could direct specific milestones in the Incentive Regulation process for transmission. However,

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[217] Tr. p.6116-6118
[218] Exhibit 202, Attachment 3
[219] EAL Evidence, paragraph 88

EAL recommended that the Board indicate to interested parties that it expects Incentive Regulation to be pursued with a view to implementation by a specific date.

EAL indicated that new TFO T&Cs set the basis for going forward with Incentive Regulation. Parties now have a better understanding of their rights and obligations and of the performance standards that can be expected from the transmission assets. The Utility responses to EAL information requests indicate that they are actively pursuing Incentive Regulation. EAL also believed that Incentive Regulation is one of the ultimate goals of restructuring, given its potential to reduce the administrative burden of the Board and the costs of regulation. However, EAL is concerned that issues that some may consider being more pressing, such as those arising from the IAT process, may cause Incentive Regulation to be delayed unless the Board provides further direction. Incentive Regulation is an important issue deserving of attention.

Position of the FIRM Customers

The FIRM Customers noted EAL's argument that it "believes that its stakeholders would prefer to have Incentive Regulation of transmission tariffs proceed within a reasonable time" and "it would be in the best interests of all parties if the Board were to provide some guidance to the industry with respect to a timetable for consideration of Incentive Regulation for transmission."[220] The FIRM Customers stated that providing an incentive to TFOs, or the TA, to do a better job when jobs are still being defined does not make sense. Specifically, before any job can be done better and more efficiently with greater cost savings, the parties need to know what first must be done and to what standard(s). Until these have been clarified with certainty, it would be premature to require the implementation of any timetable to develop an Incentive Regulation scheme. Accordingly, the FIRM Customers disagreed with EAL's request, noting that there are larger, more pressing matters to be dealt with prior to forcing a rigid timetable to develop Incentive Regulation for transmission.

Position of ENMAX

ENMAX indicated that it would be inappropriate to implement a specific date for Incentive Regulation. It noted that the current proceeding is dealing with the 1999/2000 test years and not Incentive Regulation or test years beyond 2000. The Board should confine itself to the applications before it.

ENMAX submitted that Incentive Regulation is a matter for negotiation between the interested parties and subject to the approval of the Board. Since the Board has issued guidelines for negotiated settlement processes, interested parties should be left to pursue negotiations within the context of the guidelines. This may, or may not, eventually result in agreement on Incentive Regulation. However, in ENMAX's view it would be highly inappropriate for parties to be put into a position of carrying out negotiations in the face of a pre-determination by the Board that Incentive Regulation is desirable and should be implemented by a specific date.

[220] EAL Argument, par.108

Board Findings

The Board acknowledges that a majority of the parties at the hearing agreed with some form of Incentive Regulation, however, there was disagreement on the timing and whether or not the issue should be considered as part of the present Applications.

The Board notes that TransAlta submitted that its proposed tariffs are in full compliance with the EU Act and provide appropriate and effective incentives for efficiency. EAL and IPPSA/SPPA both indicated that the Incentive Regulation of transmission tariffs should proceed within a reasonable time while EPTI and the FIRM Customers stated that Incentive Regulation should not proceed in an unreasonably short time period nor should a rigid timetable to develop Incentive Regulation be developed. The Board notes ENMAX's view that the Board should not deal with Incentive Regulation as part of the Applications before it.

The Board acknowledges TransAlta's concern with respect to deferral accounts. The Board does not believe that utilizing deferral accounts are contrary to the spirit of the EU Act, noting that, in exceptional circumstances, deferral accounts are a fair way of dealing with some specific issues. The Board notes that for the transmission function, deferral accounts are only being utilized for capital additions.

In Decision U97065, the Board concluded that:

- Traditional cost-based regulation is criticized for providing little incentive to improve efficiency, however Incentive Regulation is viewed as an alternative method of regulation to address this deficiency.
- Incentives for efficiency allow the Utilities the opportunity to share in any savings or costs relative to its targets and customers benefit through reduced costs.
- Incentive regulation also has the potential to reduce regulatory costs by avoiding the need for frequent regulatory proceedings. It may also shift regulatory resources from the detailed analysis of costs to performance monitoring and auditing.
- There are various potential benefits resulting from Incentive Regulation.

The Board acknowledges that minimizing cost and maximizing efficiency in the Alberta Electric System is important and supports the development of a process for Incentive Regulation. The Board notes, however, that the electric industry in Alberta is going through significant restructuring resulting in high workloads for the interested parties. Therefore, the Board believes that now is not the appropriate time for the Board to establish a firm time line or scheme for Incentive Regulation.

The Board supports the interested parties continuing to pursue negotiations with respect to Incentive Regulation, within the context of the guidelines which the Board has issued for negotiated settlements. The Board believes that the negotiated settlement process is preferable to the Board determining the terms of or time of Incentive Regulation.

The Board considers, however, the following direction from Decision U97065 to still be appropriate after parties have successfully completed negotiations and are seeking the Board's approval of a negotiated settlement:

> When applications for approval are filed, the Board would find the following information useful:
>
> - a fully-supported base-year forecast;
> - a description of the performance targets that will be used and the means by which performance will be measured;
> - a description of the method of identifying cost savings or other benefits;
> - a description of the manner in which cost savings or other benefits will be shared between the utility and customers;
> - a discussion of how the tariff may change over the period in which it is intended to have effect; and
> - a discussion of the content of periodic reports to be filed with the Board and interested parties for the purpose of monitoring results under the form of Incentive Regulation being proposed.[221]

The Board directs that interested parties advise the Board of the status of Incentive Regulation negotiations by the next GTA.

(c) Distribution–Deferral Accounts

The Board, in this section, must determine whether it is appropriate for pool price, reservation price and sales volume risk to rest with the DISCO or whether deferral accounts should be set up to pass variations from forecast to the DISCO's customers.

While EPGI and TransAlta opposed the use of deferral accounts, a number of deferral accounts were agreed to in the AE 1999/2000 negotiated settlement approved by the Board in U99046 dated 10 May 1999.
For AE-GENCO one deferral account will accumulate 100% of the difference between the actual and forecast hourly pool price for AE units. Another accumulates 90% of the difference between actual and forecast hourly generation by unit.[222]

[221] Decision U97065, p.56
[222] Sections 17 and 18 of the AE 1999/2000 negotiated settlement agreement

For AE-DISCO separate deferral accounts accumulate:

- 100% of the variance in both hourly Pool Price and hourly Entitlement Values with no deferral related to volumes.[223]
- Any costs and benefits of the power Pool's Voluntary Load Curtailment Program.[224]
- Any difference between actual and forecast load converted to the Direct Access Tariff.[225]
- 100% of the impact of the Board's Decision to allow AE customers on the Pool Opportunity Rate to switch to Firm rates.[226]
- Increases or decreases from forecast in transmission access payments payable by AE.[227]
- Increases or decreases in reservation payments.[228]

Position of the Utilities

AE's reasons for agreeing to a deferral account approach were set out at Tr. p.4674-4676. AE indicated that its concern over its inability to effectively manage the risks required either extremely conservative forecast assumptions, an enhanced return to reflect the enhanced risk or deferral accounts. AE concluded that deferral accounts were the appropriate solution.

TransAlta and EPGI opposed the use of deferral accounts on the grounds that such deferral accounts blunt incentives to manage risk effectively, and may actually result in inefficient choices in system operation. Neither utility explained, in other than the most general terms, how the risks associated with matters over which they have little control, in particular the pool price variability would be managed. EPGI and TransAlta opposed generation deferral accounts and TransAlta had little specific comment on DISCO deferral accounts.

Position of the Intervenors

IPCAA recommended instituting a pool price deferral account for TransAlta-DISCO, similar to that used in the Utilities' 1998 negotiated settlements. Mr. Drazen considered that removing the significant forecast risk related to pool price would reduce the DISCO and GENCO cost of capital and benefit customers. Other Intervenors supported IPCAA's proposals for deferral accounts.

LE/RD supported pool price and volume deferral accounts as described at Tr. p.4315-4317. LE/RD recognized the tradeoffs with respect to deferral accounts as described by TransAlta and EPGI, but submitted that the actual experience with deferral accounts (two years with EPGI and one year with TransAlta) have not revealed a significant blunting of the incentive to manage risk

[223] Section 28 of the AE 1999/2000 negotiated settlement agreement
[224] Section 29 of the AE 1999/2000 negotiated settlement agreement
[225] Section 30 of the AE 1999/2000 negotiated settlement agreement
[226] Section 31 of the AE 1999/2000 negotiated settlement agreement
[227] Section 32 of the AE 1999/2000 negotiated settlement agreement
[228] Section 33 of the AE 1999/2000 negotiated settlement agreement

and achieve operational excellence.[229] Given this, and the significant differences between current utility forecasts, the use of deferral accounts is the most reasonable solution to the difficulties of adequately forecasting pool prices and generation output for the test period.

LE/RD also suggested that the Board put appropriate guidelines in place with respect to the operation of the accounts including audit and transparency requirements similar to those in the AE negotiated settlement.

The FIRM Customers submitted that, if the Board accepted Dr. Kolbe's (expert witness for TransAlta) view that the DISCO required a 200 basis point premium over system average return on equity, then the Board should direct that an additional deferral account be established. Noting that Dr. Kolbe's recommendation was based on the alleged "leverage" risk posed by generation reservation payments and other retailing risks, the FIRM Customers indicated that they would rather assume the volume risk on generation reservation payments than pay shareholders compensation for such alleged leverage. Hence, if this risk is considered too large, Dr. Kolbe's recommendation should not be adopted. Instead, the Board should establish an account deferring 75% of the variance in TransAlta DISCO's generation reservation payment revenue due to differences between forecast and actual sales and charges to ratepayers. Then the appropriate return for the DISCO would be the same as for the GENCO and the Utilities' overall rate of return would be reduced by 50-75 basis points to reflect the lower risk.[230]

The FIRM Customers submitted that the Board should adopt pool price deferral accounts for both the GENCO and the DISCO. In the event of higher than forecast pool prices, without a DISCO deferral account, the GENCO would refund money to the DISCO and municipalities who own their distribution systems. That would not help the DISCO's customers and only partially reduce the incentives to exercise market power and manipulate models. The FIRM Customers recommended the establishment of both DISCO and GENCO deferral accounts.

Board Findings

As noted in the GENCO Deferral Accounts, Part 1–General, Section 3(a)(4) of this Decision, the Board considered that pool prices will be difficult to forecast with confidence throughout 1999 and 2000 due to the following:

- the tight supply demand situation,
- the timing of new sources of supply,
- the pricing of imports,
- natural gas prices, and
- the potential for the exercise of market power.

[229] Tr. p.4437-4438
[230] TAU-FIRM-19

The uncertainty surrounding these factors made it difficult to accurately forecast with confidence the hourly pool prices. Further, the Board considered that the Utilities should not be given incentives to exercise market power to affect pool prices. In these circumstances. the Board considered it appropriate to utilize a deferral account to deal with the uncertainty of pool prices for GENCOs.

The Board notes that the generation/sales forecast is an important part of both GENCO and DISCO revenues/costs. The Board considers it appropriate to establish pool price deferral accounts for both GENCOs and DISCOs for each of 1999 and 2000. Deferral accounts will ensure that 100% of the difference between the actual hourly and forecast hourly pool price is accumulated and borne by the customers of the respective GENCO or DISCO.

Accordingly, the Board directs that a pool price deferral account be established by TransAlta DISCO for the 1999-2000 period with the amount to be deferred in respect of each hour to be calculated as follows:

Pool price deferral = (Actual pool price-Forecast pool price) x (Forecast energy purchases) + (Actual DISCO entitlement – Forecast DISCO entitlement)

The Board directs that the above deferral account formula should use a forecast hourly pool price, forecast hourly energy purchase and forecast hourly DISCO entitlement developed as follows:

- Develop an average hourly pool price, average hourly energy purchase and average hourly DISCO entitlement by DISCO by averaging EPGI's PROSYM modeling iterations.
- Develop an average hourly pool price, average hourly energy purchase and average hourly DISCO entitlement by DISCO by averaging TransAlta's ENPRO modeling iterations.
- Develop the forecast average hourly pool price, forecast average hourly energy purchase and average hourly DISCO entitlement by averaging the above EPGI and TransAlta averages.

Since the Board considered it important for the GENCO to have performance incentives designed to keep units on line during tight supply situations, the Board did not establish a volume deferral account for EPGI and TransAlta generating units. The Board considers that there would be the potential for inappropriate incentives if a DISCO had a volume deferral account when the GENCOs did not. Further, the Board notes that, with a pool price deferral account, the volume risk for the DISCO has not increased over that faced in the past. Therefore, the Board will not establish a volume deferral account for TransAlta DISCO.

The Board also recognizes that, as the FIRM Customers suggest, a further deferral account is necessary to pass any cost/benefit arising to the DISCO from the GENCO pool price deferral

account to TransAlta DISCO's customers. The amount in that deferral account should be calculated annually by multiplying the DISCO's reservation payment share by the balance in each of AE, EPGI and TransAlta generating unit's pool price deferral account and summing the results. Accordingly, the Board directs TransAlta to establish a further DISCO deferral account as described above.

The Board is also concerned that DISCO customers, particularly those served on the pool price Direct Access Tariffs (DAT), see the appropriate price signals. DAT customer response to pool price improves the efficiency of the market. Therefore, the Board considers that there should be no artificial incentives to keep customers on single price level fixed rates if they prefer the actual pool price DAT or the time-of-use DAT. The Board considers that the eventual disposition of the deferral account balances to customers should reflect this principle.

(d) Audit of Deferral Accounts

LE/RD suggested that the Board implement appropriate guidelines with respect to the operation of any deferral accounts including audit and transparency requirements similar to those in the 1999/2000 AE negotiated settlement.

Guidelines for audit of the deferral account balances were set out in Section 43 of the 1999/2000 AE negotiated settlement agreement as follows:

- AE will provide an accounting of the final balances in the deferral accounts and their disposition as early as reasonably possible after 1999 and 2000. Parties to the negotiated settlement have audit rights in respect to AE's compliance with the specific terms of the negotiated settlement. While any audit undertaken would be at the expense of the party requesting it, AE is required to provide all reasonable cooperation necessary for the effective and efficient completion of the audit. An audit report prepared by the persons who complete the audit must be provided to AE.

- Parties to the negotiated settlement are required to negotiate in good faith to reach agreement on the final balances in the deferral accounts and their disposition. Any agreement will be filed with the Board for final approval. If agreement is not reached then parties will file their calculations with the Board and any party may provide a copy of any audit to the Board.

Board Findings

The Board agrees with LE/RD that it is appropriate that audit rights, similar to those in place for the 1999/2000 AE negotiated settlement, be in place with regard to the deferral accounts arising out of this Decision. Such rights may assist parties in reaching agreement on the final balances in the deferral accounts and their disposition.

Therefore the Board directs both TransAlta and EPGI to apply to the Board for approval to collect or refund the balance in all their deferral accounts (e.g., GENCO accounts for EPGI and GENCO and DISCO accounts for TransAlta) by 1 April 2000 for disposition of the balances at year-end 1999 and by 1 April 2001 for disposition of the balances at year-end 2000.

A similar need exists for the ability to audit accounts and balances associated with the wide variety of accounts and issues that will result in balances being handled by the Balancing Pool. Accordingly, the Board directs AE, EPGI, EPTI and TransAlta to follow and make available the equivalent audit processes and provisions to accounts and balances being handled by the Balancing Pool as described in this section on the audit of Deferral Accounts. The Board directs that the same provisions for paying for the audit process will apply as described in this section.

The Board directs TransAlta and EPGI to include the following in their application:

- Provide an accounting of the final balances in their applicable deferral accounts and a proposal to deal with their disposition to all parties to the 1999/2000 proceeding.
- Allow any party/parties to the 1999/2000 proceeding audit rights (using an auditor acceptable to the Utility and the party/parties) in respect to compliance with the specific terms of each deferral account, providing the party/parties agree to fund the audit and provide the Utility with a copy of the audit report prepared by the person(s) performing the audit.
- Provide all reasonable cooperation necessary for the effective and efficient completion of any audit.

Further, the Board directs that, the parties apply to the Board, upon completion of the audit, for a determination of how the costs of the audit should be split amongst the parties. The Board will determine who should pay the cost of the audit. The Board considers that the costs may be:

- Shared among the Utility, its customers and the party requesting the audit in the normal course of events. Alternatively, the costs could be recovered from the savings identified in the audit.
- Borne by the Utility if, for example, the error arose from a lack of attention to the Board's directions, or .
- Borne solely by the party requesting the audit if, for example, the Board were to determine that the audit was vexatious or frivolous.

In making this determination the Board will consider whether or not the audit process was required and/or resulted in savings to customers.

The Board also expects parties to the 1999/2000 proceeding to negotiate in good faith to reach agreement on the final balances in the deferral accounts and their disposition. Any agreement would be filed with the Board for final approval. If agreement is not reached then the Utility will

file its calculation and proposal with the Board for resolution. Any party may provide a copy of any audit to the Board.

(e) Taxes Other than Income Tax

Existing Assessment Rules

Property in electric generating plants is assessed under the *Municipal Government Act* (MG Act) as linear property. Section 284(1)(k)(i) defines linear property as including:

> ...electric power systems, including structures, installations, materials, devices, fittings, apparatus, appliances and machinery and equipment, owned or operated by a person whose rates are controlled or set by the Public Utilities Board or by a municipality or under the *Small Power Research and Development Act*, but not including land or buildings.

Linear property is assessed by the Provincial Government pursuant to s.292(1) of the MG Act. This includes all property at an electric generating plant, except for land or buildings. All the linear property at an electric generating plant falls within the definition of "machinery and equipment," defined in section 1(g) of Standards of Assessment Regulation AR 365/94. The definition of "machinery and equipment" applies both to linear property and other property (e.g. manufacturing and processing plants). The definition of machinery and equipment reads, in part, as follows:

> "machinery and equipment" means materials, devices, fittings, installations, appliances, apparatus and tanks other than tanks used exclusively for storage, including supporting foundations and footings and any other things prescribed by the Minister that forms an integral part of an operational unit intended for or used in
>
> (i) manufacturing,
>
> (ii) processing,
>
> ....
>
> (vi) an electric power system, ...

The assessment and taxation of linear machinery and equipment and non-linear machinery and equipment is quite different.

- First, linear machinery and equipment is subject to provincial school tax whereas non-linear machinery and equipment is not.[231]

[231] Tr. p.1095, l.22; p.2691, l.21

- Second, Assessable Property Regulation AR 367/94 requires linear machinery and equipment to be assessed at 100% of its value whereas non-linear machinery and equipment is assessed at 77%.[232]

Potential Assessment Rule Changes

Pursuant to the foregoing existing assessment rules, regulated electric generating plants owned by AE, EPGI, TransAlta and SPP plants are presently taxed at a significantly higher level than other industrial and electric plants within Alberta.

Owners of regulated electric generating plants have requested that the Government review the assessment rules for linear property to make the rules consistent with the assessment rules for non-linear machinery and equipment. The Government has agreed to the review and has targeted any changes to be effective for the 2000 tax year.

The FIRM Customers summarized the potential impact of the assessment rule change as follows:

> If the provincial school tax is eliminated for linear M & E, then the total reduction in property taxes for TAU and EPGI will be in the range of $15 million. If the value for linear machinery and equipment is changed from 100% to 77%, there will be still further reductions in property tax paid in the year 2000. The information available indicates this would be in the $2-3M range for TAU and EPGI, combined. Obviously, this is a very significant amount and supports the suggestion total linear property tax reductions province wide would be around $27M if the two identified changes are made.[233]

Deferral Account

The issue to be decided by the Board is whether to approve a deferral account to deal with potential changes to the rules for assessing generating plant.

Position of the FIRM Customers

The FIRM Customers believe there are unusual circumstances relating to property taxes for the year 2000. At best, there is a high degree of uncertainty about the assessment and taxing regime that will be in place for the year 2000. Most likely there will be significant legislative changes, substantially reducing the property taxes payable by generating Utilities in connection with electric generating plants. Given this uncertainty and the significance such changes could have on property tax assessments, the FIRM Customers submit the only appropriate manner for dealing with 2000 property taxes is to establish deferral accounts for TransAlta, AE and EPGI.

[232] Tr. p.1097, l.23; p.2691, l.6
[233] FIRM Customers Argument, p.63

AE Negotiated Settlement

The potential change in the property assessment and taxing regime is addressed in the Board approved AE negotiated settlement. Specifically, section 36 of the Settlement Agreement states all costs arising from "legislative changes" will be flowed through AE's Aggregate Reservation Price, dollar for dollar. AE agrees there will be a truing up of any increase or decrease in costs arising out of changes in the legislation.

Position of EPGI

Dr. Bridgeman summarized the Corporation's position as follows:

> Sir, within the realm of a normal forecast, certain rules can change, and so long as the changes aren't significant, we don't think there ought to be deferral accounts. I know that Mr. DeSarkar has a concern that some of the rules may be changing that might increase property taxes to EPTI that we didn't anticipate, so once a filing is put to bed, things go up, and things go down, and that is the forecast that we are prepared to live with, and we will do the best we can do. Now, if there is a very significant change in the rules, we wouldn't propose to reap a gain because of that if it was very significant, so within the normal course, assessments change. They go up; they go down. They are forecast; they are wrong. I don't believe that we think a deferral account is appropriate in that instance. But if there is a fundamental change in law, a fundamental change in the rules, and it caused a significant change, and you brought one to the table, it probably wouldn't be unreasonable to consider that.[234]

Position of TransAlta

Mr. Way summarized TransAlta's position in response to a question by Mr. Burgess as follows:

> Q Let me ask this question, then: Would TransAlta agree to a deferral account for property taxes on generating plants for the year 2000 given the uncertainty as to what the level of taxes might be at this point?
>
> A MR. WAY: So we have not proposed a deferral account for these taxes, and we would not agree to one. Like anything else, we believe that having the incentive there for the first year or two and leaving an incentive with the company, then customers pick up the results of the gains made by the company in future years and enjoy those benefits from them in an ongoing basis. That is a feature of prospective rate-making. It seems to promote continued efficiency into the future and continued cost-savings, and I guess our perspective on deferral

[234] Tr. p.1099

> accounts is they would remove that to a short-term and long-term disbenefit of customers and the industry.[235]

TransAlta further elaborated on its position in reply argument as follows:

> FIRM, at page 65, recommends the establishment of a deferral account for property taxes because of the possibility of significant legislative change and because "[this] situation has little, if anything to do with productivity or incentive". With respect, TransAlta submits that this situation is an excellent example of the problems with deferral accounts and the benefits of prospective rate making. TransAlta has been devoting significant management resources in an attempt to get the current legislative framework changed in order to reduce future property taxes to the benefit of customers. While there might be some benefit to shareholders in the short term (although the evidence is that legislative change is unlikely during the test period, and even if property tax assessments are reduced this benefit could very well be at least partially offset by concomitant increases in mill rates) customers would benefit in the longer term if TransAlta's efforts are ultimately successful. However, with a deferral account in place, TransAlta would not have the same incentive to pursue this type of legislative change and customers would ultimately be worse off. Accordingly, TransAlta submits that the Board should reject the establishment of a deferral account for property taxes.[236]

Board Findings

The Board considers a deferral account for GENCO taxes other than income for the test year 2000 would be appropriate in view of the possibility that the assessment rules will be changed in the year 2000. The Board, in previous proceedings, has allowed the effect of legislative changes beyond the control of the company to flow through to customer rates.

The Board notes TransAlta's concern that a deferral account removes incentives for the company. The Board considers, when a playing field is not level, that the company has a strong incentive to lobby governments to reduce taxes regardless of whether a deferral account is established or not. Further, the Board notes that the final decision respecting assessment rules rests with the Provincial Government and is outside the control of the company.

The Board will determine an appropriate baseline forecast for GENCO taxes other than income based on existing assessment rules.

Accordingly, the Board directs EPGI and TransAlta to establish a deferral account for the year 2000 for GENCO taxes other than income only if assessment rules are changed and are

[235] Tr. p.2702
[236] TransAlta Reply Argument, p.65

applicable to the 2000 tax year. The Board considers that the effect of any changes to GENCO assessment rules beyond the year 2000 will be dealt with in the PPA process.

The deferral account shall identify the changes to the approved baseline forecast GENCO taxes other than income caused by the change in the assessment rules. The Board directs EPGI and TransAlta to apply to the Board for approval of the disposition of any positive or negative balances in the deferral account.

(f) Inventories

The appropriate treatment of GENCO inventories as of 31 December 2000 was raised during the proceedings.

Position of ENMAX

The Board has typically adopted the view that necessary working capital includes amounts reflecting the investment in inventories of materials, supplies and other assets necessary to the O&M of the utility system. That view was most recently confirmed in Decision U97065.[237] As well, the Board also recognized that inventories such as emergency coal are in place to cover the risk of the time it would take to rectify down times under certain circumstances. As such electric consumers across the province have compensated the applicants for this risk by way of the financing costs for holding those inventories.

As part of the government's mandate to deregulate the generation market, PPAs will essentially be sold under bilateral agreements.[238] This notion will involve a different set of customers than under predecessor regimes. Revenues will be collected and costs will be attributed to that different set of customers. Risks will also be treated differently and attributed to a different set of customers. As a result, compensation for financing inventories will also change. Customers in the current regime certainly have no entitlement to inventories after 2000 and equally they do not need to cover the risk associated with inventories under the PPAs or finance those inventories. The parties to the bilateral agreements should not benefit from the inventories financed by customers.

EPGI maintains a 45-day supply of emergency or dead coal.[239] This 45-day supply will not be needed by the current power purchasers on the very last day of 2000. The only need for the 45-day supply, at that point, will be for the benefit of whoever purchased the PPA for 2001 and beyond.[240]

[237] Decision U97065, p.307
[238] Tr. p.274
[239] Tr. p.275
[240] Tr. p.278

Under the mid year convention, it follows that a zero balance for inventories should be included in the determination of the mid year working capital. Customers have lived by the mid year convention, no matter whether year-end amounts were higher or lower than necessary for the operations during the year. Now when it turns against them, the GENCOs are fighting the consistent application of the mid year convention.

EPGI raised the possibility that the auction process may not work,[241] but that is purely speculative at this juncture. The legislation mandates the PPA process after 2000 and therefore the Board must gear its findings to moving to that new process. The GENCOs have made filings as if the PPAs will function. If the PPA process was not imminent, the GENCOs acknowledged that they would have made very different filings. Moreover, TransAlta and EPGI have filed PPAs with the IAT. If they had reason to believe that the PPAs will not function, they had other remedies at their disposal versus speculation and conjecture at this proceeding.

Therefore, ENMAX submitted that all EPGI and TransAlta inventories (including emergency coal, live coal and material and supplies) should be set to zero as at 31 December 2000, and the resulting mid year calculation of working capital should reflect those zero balances.

Position of EPGI

EPGI failed to see how any value for customers would be realized through the administrative effort required to carry out ENMAX's suggested exercise to set inventories to zero as at 31 December 2000. In addition, the Board would need to ensure that the impact of the exercise flowed through as appropriate to the PPAs.

Each of the inventories will have to be in place as of the beginning of 2001. Therefore, if one were to zero out the inventories for GTA purposes by the end of 2000, they would have to be built up again by the beginning of 2001 to support operations under the PPA regime. As well, EPGI's carrying costs incurred in 2000 in respect of the PPA period would need to flow through to customers under the PPA regime.

As customers will be essentially the same under each regime, customers will derive no value from ENMAX's proposal. EPGI submits that implementing ENMAX's suggested exercise provides no benefit to customers, places an additional administrative burden on the Board and EPGI and, consequently, should not be accepted by the Board.

Board Findings

The Board notes that customers pay only the carrying costs of inventories and have not paid the costs of building up the inventories. The Board considers that inventories are a necessary part of doing business pre and post 2001. The Board agrees with EPGI that "if one were to zero out the inventories for GTA purposes by the end of 2000, they would have to be built up again by the

[241] Tr. p.280

beginning of 2001 to support operations under the PPA regime."[242] The Board also agrees with EPGI that implementing ENMAX's proposal provides no benefit to customers and places an additional administrative burden on the Board and EPGI. The Board considers that intergenerational equity is maintained by including the associated carrying costs of an appropriate level of inventories in the revenue requirement pre-2001 and in the PPAs post 2001. Accordingly, the Board rejects the ENMAX suggestion to zero-out all inventories as of 31 December 2000.

(g) Balancing Pool

The use of the Balancing Pool as a mechanism to deal with accounts that need to be settled as of 31 December 2000 was raised during the proceedings.

Position of the FIRM Customers

The FIRM Customers considered that all accounts requiring a truing up at the end of 2000 should be handled through the Balancing Pool.

Position of ENMAX

In reference to a number of matters which involve lingering balances in deferral accounts or reserve accounts, ENMAX suggested that parties to the proceeding witnessed knee-jerk reactions by the panels for both TransAlta and EPGI. Their standard response was an expectation that these deferral and reserve account balances would be taken care of by the Balancing Pool.

The EU Act addresses the Balancing Pool in sections 45.96 and 45.97 of the EU Act. There are, as of yet, no regulations or rules with respect to the Balancing Pool. Therefore, parties are left with only a very general sense of what is intended by the government. More importantly, the legislation with respect to the Balancing Pool deals only with matters arising out of the PPA process. There are no provisions that deal with transition items from the existing regulatory regime for generation. Based on the information on the record, there is no reason to expect that the government intended to deal with lingering customer balances of the current regime through the Balancing Pool.

[242] EPGI Reply Argument, p.10-13

Throughout the hearing, TransAlta made broad sweeping assumptions that current balances which are due to customers should remain in the existing accounts and will be dealt with by the Balancing Pool after 2000.[243] Expectations such as these are merely speculative. The post 2000 regime for costs of generation is vague at best. Moreover, what we do know is that the PPAs will be bilateral contracts between the individual GENCOs and power purchasers.[244] Therefore, each of the generating Utilities will have a different set of customers than they do under the current regime.

The record clearly shows that there are no rules in place to govern the Balancing Pool. In fact, the uncertain status of the Balancing Pool and the lack of rules for it were specifically noted by TransAlta.[245] Neither the parties, nor the Board, know what form it will take. Moreover, there is nothing on the record that will provide assurance that balances in reserves and deferrals, which were collected prior to 2001, will be treated correctly or consistently with how they were originally collected. The lack of defined rules for the Balancing Pool dictates that the pool should not be relied on as an automatic default mechanism to act as a receptacle for deferral and reserve accounts.

The regulatory accounts of both TransAlta and EPGI contain a number of amounts which are comprised of customer funds collected to offset uncertainties and smooth costs year to year. Any delay in refunding those amounts to customers will benefit TransAlta and EPGI and impose costs to entitled DISCOs and their customers. After 2000, it is likely that the Board will not have jurisdiction over these accounts and their disposition to the GENCOs could quite easily go unnoticed.

Witnesses for both TransAlta and EPGI have made their positions clear regarding deferral accounts. The need for these accounts will terminate at the close of 2000. The regulation of deferral and reserve accounts is rooted in long standing and generally accepted principles which should not be supplanted. ENMAX submits all reserve account balances should be reduced to zero at 31 December 2000, and the Board should impose mechanisms to deal with any outstanding credits or charges.

Position of EPGI

ENMAX mischaracterizes EPGI's evidence by suggesting that the Corporation provided a "knee-jerk reaction" in suggesting that any outstanding balances in reserve and deferral accounts could be addressed through the Balancing Pool.

EPGI's proposed approach was thoroughly described by Dr. Bridgeman in his response to an undertaking provided at Tr. p.263.[246] In summary, Dr. Bridgeman stated that when and how an

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[243] Tr. p.1919, p.2326, p.2380, p.3076, p.3966, p.4223, p.4238
[244] Tr. p.274
[245] Tr. p.1972, 3453
[246] Exhibit 23

adjustment should be made depends on the adjustment account at issue. For example, in the case of the fixed ancillary service payment deferral account, the amounts will be known well before 31 December 2000, so there will be plenty of time to reflect the adjustments in EPGI's reservation price and the DISCOs' retail rates. In the case of the Hearing Cost reserve account, the required adjustment should be known by mid-2000 with some certainty. For activity that might occur beyond mid-2000, a forecast could be made of the adjustment, which would leave sufficient time for the entitled DISCOs to reflect the adjustment in retail rates.

In neither of these examples did EPGI propose to address the outstanding balances through the Balancing Pool. Even in the case of section 78 costs and EPGI's reserve for injuries and damages, there could be a cut-off date by mid-2000 with the outstanding balances dealt with prior to the end of 2000. EPGI is proposing that any adjustment over the remainder of the year would be recovered through the Balancing Pool since a claim may not occur until late 2000 or perhaps until after year end.

The evidence demonstrates that EPGI has proposed a fair and workable mechanism for dealing with outstanding balances as at the end of 2000.

Board Findings

The Board considers that the Balancing Pool is an appropriate mechanism to handle the outstanding balances in accounts that will no longer be necessary under the post 2000 regime.

The Board interprets subsections 6(h) and 7(1)(g) of the Balancing Pool Regulation AR 169/99, as providing the Balancing Pool with the authority to accept Board approved credits and charges from the GTA process and to pass these on to the consumers.

In the event that any matter should be handled through the Balancing Pool but was not so directed by the Board, the Board will accept applications from any party to have this matter addressed.

In the earlier section, Audit of Deferral Accounts, the Board directed an audit process will apply to any amounts to be handled through the Balancing Pool. The Board directed that the same audit process will apply as was directed to apply to the audit process for Deferral Accounts.

With respect to interest on any outstanding balance in any account to be handled through the Balancing Pool as of 31 December 2000, the Board directs that its normal Guideline on interest will apply.

(h) Business Risk and Capital Structure

Introduction

In the Business Risk and Capital Structure section, the Board will first determine the business risk associated with the integrated utility. Having determined the business risk of the integrated

utility, the Board will be in a position to assess any changes that have occurred in terms of overall business risk since the 1996 GTA, the time of the last Phase 1 Proceeding. Accordingly, to the extent that the Board determines that integrated utility risk has changed, the Board will be able to establish an appropriate common equity ratio and capital structure for the integrated utility, which may differ from the capital structure approved in 1996. In essence, the new capital structure will reflect the overall change in business risk since 1996 combined with an assessment of financial risk for the integrated utility.

The Board will then examine the business risks of the GENCO, TRANSCO and DISCO functions in relation to the integrated utility business risk. Once the business risks of the separate business functions have been established, the Board can then determine appropriate common equity ratio differentials relative to the common equity ratio of the integrated utility. The differentials will reflect the difference in business risks between the risk of the specific function and the risk of the integrated utility. Through this process, the Board can then determine the capital structure of the separate business functions, incorporating the unique business risks of the individual functions. In support of the Board process to determine the capital structures for the business functions, the common equity ratios of the individual business functions, weighted by the corresponding rate base of the functions, when aggregated will be in balance with the overall common equity ratio of the integrated utility.

In Decision U97065, the Board reviewed in detail the impact of the EU Act on the business risk of Alberta electric utilities. The Board concluded that there was no material change to the overall business risk of the integrated utilities. Somewhat lower capital recovery risk was roughly offset by somewhat higher risk associated with GENCO surplus/shortfall and DISCO purchase power costs. The Board determined that risk had changed for both the GENCO and DISCO functions, but concluded that there was not sufficient information available at the time to make a full determination of the effect of risk by function on capital structure and fair return.

Since Decision U97065, the EU Act has been amended. Most significantly, the amended Act will replace the system of legislated hedges currently in place with PPAs, a set of long-term legislated arrangements that will provide a pre-determined return on investment for existing GENCO units over a 20-year period beginning in 2001.

In Decision U97065, the Board ordered the utilities to file evidence regarding the business risk facing the individual functional components of the integrated utilities at the time of their next general rate application. The Board is of the view that there is now sufficient evidence to arrive at a fair assessment of business risk for each of the functional elements of the utilities. The Board will reflect its findings respecting business risk and return by function in fixing prices and tariffs by business function.

In terms of defining business risk and investment risk, the following excerpt from the Board Findings for Capital Structure in Decision U97065 summarizes the Board's perspective on risk in the current proceeding:

> An appropriate capital structure keeps the utility's total investment risk (which is a function of business and financial risks) at a level that will allow the utility to raise equity, debt and preferred financing at a fair overall average cost to customers. Generally, investment risk is the risk of a market security as appraised by investors. Business risks are all of the physical, economic, political, competitive and regulatory risks to which the utility is exposed. Financial risks are the risks relating purely to the capital structure used to finance the assets of the utility. The greater the proportion of debt and preferred (i.e., fixed-charge financing) to total capital, the greater the financial risk.[247]

In general, business and financial risks tend to be inversely related to each other. As a result, businesses such as utilities that have characteristically lower business risk are able to assume a greater degree of financial risk by incorporating higher amounts of debt in their capital structure. Once the business risk of a utility has been determined, it is important to address the appropriate capital structure for the utility, acknowledging the overall financial risks.

Setting the appropriate capital structure for the Utilities is a necessary part of determining the utilities' shareholders return and the overall cost of service to customers. Varying the amount of debt and equity used to finance rate base can affect the overall composite level of financing costs. Debt costs are tax deductible and are therefore less expensive than the cost of equity. However, as the level of debt increases, the utility will be taking on more financial risk and the cost of debt and equity will consequently increase.

Thus, increasing or decreasing the common equity ratio in a utility's capital structure will in turn decrease or increase the utility's financial risk and ultimately the investment risk experienced by bondholders and shareholders. As a result, the appropriate capital structure needs to balance the interests of the utility's bondholders and shareholders with the interests of the ratepayers. Accordingly, by determining an appropriate capital structure for the utility, the Board seeks to maintain the utility's financial integrity and its ability to raise capital while minimizing the overall cost of capital to ratepayers.

TransAlta proposed an ATWACC model in the current proceeding. A major outcome from the ATWACC approach is that utility management is allowed to determine the capital structure for the corporation. At the same time, the overall approach to capital structure in the current proceeding was unchanged from the past since the applicants and interested parties presented the traditional approach to capital structure in their evidence and arguments.

[247] Decision U97065, p.229

3. GENCO/TRANSCO/DISCO
(h) Business Risk and Capital Structure

The following table presents TransAlta's submission with respect to common equity, preferred equity and debt ratios for 1999 and 2000, in comparison to the capital structure approved by the Board in Decision U97065:

TransAlta	1999/2000	Decision U97065
Common Equity	42.0%	40%
Preferred Equity	9.5%	10%
Debt	48.5%	50%

The following table presents EPGI and EPTI's submission with respect to common equity and debt ratios for 1999 and 2000, in comparison to the capital structure approved for EPI by the Board in Decision U97065:

EPGI/EPTI (Formerly EPI)	1999 EPGI	2000 EPGI	1999 EPTI	2000 EPTI	Decision U97065 EPI
Common Equity	46.0%	48.8%	35.3%	34.1%	34.8%
Preferred Equity	0%	0%	0%	0%	0%
Debt	54.0%	51.2%	64.7%	65.9%	65.2%

The Applicants, EPGI/EPTI and TransAlta, submitted evidence respecting business risk.

Drs. Waters and Winter submitted evidence respecting business risk on behalf of a group of COCI. Mr. Drazen supplemented the COCI evidence respecting certain business risk issues on behalf of IPCAA.

Mr. Marcus submitted evidence respecting business risk on behalf of the FIRM Customers.

(1) Integrated Utility Business Risk and Capital Structure

Position of TransAlta

TransAlta requested a target common equity component of 42.0% together with 48.5% debt and 9.5% preferred stock for 1999 and 2000 for its integrated utility. In the last Phase I proceeding, TransAlta also requested a common equity ratio of 42%. However, in Decision U97065, the Board approved a deemed capital structure of 40% common equity, 10% preferred equity and 50% debt. In its Decision, the Board noted that TransAlta's requested common equity ratio of

42% was 2% higher than the 40% awarded in 1993 and higher than the 40% maximum deemed appropriate under restructuring.[248]

To the extent that the Board establishes a capital structure for the electric utilities, TransAlta submitted that a target common equity component of 42.0% combined with 48.5% debt and 9.5% preferred stock is entirely reasonable for 1999 and 2000. This capital structure is appropriate given the risks faced by TransAlta, as testified to by Mr. Waiand, Mr. Falconer and Drs. Vilbert and Kolbe.

TransAlta submitted that a capital structure including a 42% common equity component for 1999 and 2000 is appropriate for the following reasons:

- Higher levels of business risk in general related to industry deregulation; and, increased competition, particularly with respect to industry restructuring in Alberta;
- Increased volatility in the capital markets following the turmoil in the economies in Asia, Russia and Latin America; and
- The need to maintain a high quality credit rating to provide sufficient financial flexibility and the ability to access capital in order to meet the significant refinancing obligations during 1999 and 2000.

TransAlta submitted that both Drs. Kolbe and Vilbert testified that the risks in the 1999/2000 period are the appropriate risks to consider. Thus the longer-term view is only appropriate when it is required as a tie-breaker.

Mr. M. Waiand, Treasurer of TransAlta, presented evidence regarding the business environment and business risks that TransAlta will be experiencing in the future, noting that there will be a more competitive environment as a result of deregulation. In the early stage of PPA negotiations, there will be uncertain earnings and cash flow streams from generation assets. Legislative hedges, which will influence two years of cash flow, ultimately represent only 10% of the present value of TransAlta's cash flow forecast.

Mr. Waiand also stated that a downgrade by Dominion Bond Rating Service (DRBS) and a negative outlook by Canadian Bond Rating Service (CRBS) have influenced TransAlta's business environment. The changes in the outlook reflect regulatory uncertainty, increasing competition and reduced equity. With respect to U.S. deregulation, U.S. investor-owned electric utility companies have experienced credit downgrades, resulting in average bond ratings in the Single A (low) / BBB (high) area.

In summary, Mr. Waiand concluded that there is greater overall risk for TransAlta in 1999 and 2000. With respect to the post-2000 period, there will be greater predictability for the generation

[248] Decision U97065, p.231

business under PPAs. However, there will also be uncertainty regarding retail competition in 2001 and thereafter.

Mr. R. Falconer, Vice Chairman, CIBC Wood Gundy Securities Inc., provided evidence on behalf of TransAlta as to the effect of the amended EU Act on the security industry's perception of risk for TransAlta. As a result of the electric industry restructuring, TransAlta is exposed to additional business risk, including uncertainty as to the eventual industry environment. The change to a competitive environment in the electric industry will force TransAlta to position itself to deal with the new risks created by uncertainty. Competition is inherently more risky than regulation. New risks include competition, a new regulatory framework and transitional uncertainties.

Mr. Falconer confirmed that the investment world will continue to view TransAlta on an integrated basis. Financial and credit performance will be based on an integrated company since one entity exists for both legal and financial purposes. In addition, since each business segment is not truly on a stand-alone basis, investors will expect TransAlta to provide support to a weak business unit during difficult periods.

As a result of the increased business risks described above, TransAlta has taken steps to increase its common equity as reflected in the financing plan.[249] The financing plan includes:

1. *Retain a AA rating of its senior debt:* TransAlta has approximately $450 million of refinancing during 1999 and 2000 and accordingly the maintenance of a AA credit rating is critical in order to ensure that TransAlta has the flexibility to raise the capital at rates and times that provide the lowest possible cost of financing.

2. *Reduce the debt component of the capital structure in order to achieve and maintain the financial ratios consistent with a AA rating:* As part of this plan, TransAlta Corporation issued some $200 million of new common shares in November of 1998 and invested some $60 million of these proceeds in TransAlta Utilities as common equity effective 31 December 1998. This increased TransAlta Utilities common equity component of capitalization to approximately 42% and reduced its debt accordingly.

3. *Introduce a level of junior subordinated debt which has equity like characteristics:* These securities are treated as being substantially the same as equity for purposes of rating agency ratios due to their deep subordination and long tenure but have a lower cost than traditional equity due to the interest payments being deductible for tax purposes.[250] TransAlta Corporation issued some $175 million of such securities (referred to as "Preferred Securities") in April of 1999. It is expected that some portion of these

[249] Exhibit 13, Binder #1, Section 6.1, p.15
[250] Tr. p.4171ff

proceeds will be invested in TransAlta Utilities during 1999 in order to further increase its common equity component consistent with point 4 below.

4. *Migrate to higher equity levels:* TransAlta intends to increase its equity component to 43% for 2001, consistent with the equity levels of US investor owned electric utilities, as TransAlta believes that it faces business risks consistent with those faced by such utilities.

TransAlta Utilities stated that it is critical for the utility to maintain a high quality credit rating and to avoid a downgrade since it has significant refinancing obligations in 1999 and 2000. TransAlta also confirmed that CBRS has a negative outlook on TransAlta's credit rating due to regulatory uncertainty, increased competition and reduced equity. Any major downgrading of a company can create a negative bias against purchasing any new securities issued by that company. This is especially true during periods of time that industries are in transition, as is currently the case in the Alberta electric industry.

Mr. Falconer cautioned that capital market circumstances have changed dramatically from what has been typical over the past two or three decades. It is becoming increasingly difficult for corporations to access capital. Yield spreads for corporate bonds, particularly BBB rated and below, have widened dramatically and volatility in the stock market is very high.

Mr. Waiand, the Treasurer for TransAlta, presented a comparison of TransAlta's debt to capital ratio and interest coverage ratio with the ratios of other Canadian investor-owned Canadian utilities and U.S. investor-owned electric utilities.[251] Mr. Waiand stated that for 1997 TransAlta's debt to capital ratio of 48.6% and interest coverage ratio of 3.5 times were significantly worse than comparable double AA rated Canadian companies (40.3% and 4.0x, respectively) and significantly better than single A rated Canadian companies (58.9% and 2.4x, respectively). Also, TransAlta's debt ratio was only slightly better than the U.S. electric industry (50.7%) and its interest coverage ratio was similar to the U.S. industry (3.1x) after taking the difference in Canadian and U.S. income tax rates into account. However, the U.S. electric industry had an average rating in the range of A(low) to BBB(high) by Standards and Poors. As a result, Mr. Waiand argued that this analysis supports TransAlta's view that it will need to reduce debt to capitalization and increase the equity ratio in order to maintain a quality credit standing and avoid a further credit rating downgrade.

Position of EPGI/EPTI

With respect to overall business risk, Ms. McLeod, EPGI and EPTI's capital markets expert, stated:

> From the perspective of a capital markets participant, the key determinant of the business risks of EPTI and EPGI is the operating environment which will exist for

[251] TransAlta Application, Section 6

> the Alberta electric industry under the Electric Utilities Act ("EUA"). For the transmission companies, the future operating environment will not be materially different than that which has existed historically. For the generation companies, however, the future operating environment will be fundamentally altered by the Power Purchase Agreements ("PPAs") which will set out the contractual rights and obligations of the various owners and buyers."[252]

The individual aspects of business risk were examined by Dr. Robert Evans, President of Economic Research Associates. Dr. Evans' comparison of business with 1996 risks included: diversification risks and benefits, pool price risk, expense forecast risk in 1999/2000, cost indexing risk in the PPA period, changes to power pool rules, availability forecasting risk and regulatory risks.[253]

Based on his business risk analysis, Dr. Evans concluded that the 1999/2000 business risks are significantly higher than the business risks that existed in 1996.[254] Analyzing the business risks, Ms. McLeod also concluded:

> In my opinion, the prospective PPA regime, on balance, exposes the generation companies to greater business risk than has existed historically due to the 20-year term of the agreements, a period during which no regulatory review or renegotiation of contract terms is contemplated. As a result, the generation companies will be exposed to greater cost recovery risk than has historically existed, with the likelihood that earnings will be materially more variable than in the past.[255]

As a result, EPGI concluded that its long-run business risks are greater than the business risks of Edmonton Power's generation function in 1996.

Based on his assessment of EPTI's business risk, Dr. Evans also concluded that:

- The 1999/2000 business risks of EPTI are greater than the TRANSCO business risks of Edmonton Power in 1996 largely due to the absence of diversification benefits.[256]
- If the absence of diversification benefits in 1999/2000 is ignored, then EPTI's 1999/2000 business risks are not materially different from those that existed for Edmonton Power TRANSCO in 1996.[257]

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[252] ENMAX.EPGI-22(d), p.3
[253] Exhibit 4, p.26
[254] Exhibit 4, p.31
[255] ENMAX.EPGI-22(d), p.4
[256] Exhibit 4, p.42-43
[257] Exhibit 4, p.42-43

Position of the Intervenors

Position of IPCAA

IPCAA submitted that the EU Act made a fundamental and far-reaching change with respect to business risk. The regulated GENCOs no longer have any obligation to build new generation to meet increasing load. The provision of new generation capacity was thus left to the market. As a result, this change has removed a significant source of risk from these utilities since they no longer have to finance new generation and they do not need to be concerned about the potential for the investment to be disallowed or being granted a lower rate of return (which occurred with Keephills and Genesee). In this regard, it is important to note that Generation has always been the largest component of the utility companies' capital investments.

IPCAA argued that the effect of this change is still not fully appreciated and has not been incorporated into current thinking. For example, TransAlta's witness, Dr. Vilbert, stated:

> In addition, there is value in providing financial flexibility to the utility in recognition of its public service obligation which means that the utility must have access to the capital markets irrespective of market conditions.[258]

In response to this example, IPCAA stated that the change in the extent of the regulated utilities' "public service obligation" should be recognized in evaluating the cost of capital. Thus, the statement by Dr. Vilbert is overstated in terms of TransAlta's present public service obligation. Ultimately, the continued reliability of the electric system is no longer related to the financial strength of the utilities. As a result, no matter how strong any utility is, new generation is not necessarily being provided by the regulated utilities.

IPCAA disagreed with Dr. Evans' argument that the cost of capital for 1999 and 2000 must take into account the effect of the PPAs. Dr. Evans argued that the PPA regime needed to be acknowledged when estimating the appropriate capital structure ratios and fair return on common equity for 1999 and 2000.[259]

IPCAA submitted that there is no basis for assuming that the PPAs justify a higher return in 1999 and 2000. First, there is no certainty that the PPAs will be implemented. For example, the utilities have the right to sell their plants, a possibility being examined by EPCOR Utilities Inc. Also, the PPAs may be rejected by the markets.

IPCAA argued that there is not anything on the record to demonstrate that PPAs will increase risk. In fact, the PPAs may have the effect of decreasing risk. In addition, the final form of the PPAs was not yet established by the time of the current proceeding, so there is no basis to determine what risk effect the PPAs will have. Finally, IPCAA claimed that even if it was accepted that PPAs represent higher risk to the owners, incorporating a higher risk in 1999 and

[258] BR.TAU-45
[259] Exhibit 4, p.3

2000 is contrary to the goal that PPAs should preserve the residual value of the plants for customers.

Position of COCI

COCI submitted that the Board should accept the evidence of Dr. Waters and Dr. Winter on capital structure and find that the appropriate level of common equity in the capital structure of TransAlta is 35%.[260]

The COCI also submitted that the issue of business risks in the new, market-oriented environment established by the EU Act was the subject of extensive discussion in the 1996 GTA. Based on the evidence and arguments presented on business risk, the Board concluded that there was no material change to the overall business risk of the integrated utilities.[261] As a result, no adjustment to utility capital structure was warranted.

The COCI stated that the issue for the current proceeding is whether any changes have occurred since 1996 that would warrant a revision to the assessment of business risk of the utilities, either on an integrated or functionalized basis. The COCI stated that the only business risk evidence to be considered was that of TransAlta and that of Drs. Waters and Winter; AE had reached a negotiated settlement of its application and in addition it was inappropriate to apply capital market analysis to the municipally-owned, non-taxable Edmonton Power utilities.
In their assessment of the risk impact of the amended EU Act, Drs. Waters and Winter focused on the change in long-run risks. They analyzed long-term risks because equity investors have long-run investment horizons.[262] The conclusion drawn by Drs. Waters and Winter was that the most fundamental business risk issue arising from the EU Act — whether shareholders will continue to be fairly compensated for the risks that they face in the future — has been dealt with in ways that do not act to the detriment of shareholders. Thus, long-term business risks have not increased for the vertically-integrated utility companies. There has, however, been some inter-functional reallocation of risk, contributing to the sector-specific capital structure recommendations.

The COCI discussed the fact that the historical experience of the utilities with respect to regulatory risk can be measured by the stability of their achieved rates of return. By comparing the rate of return on equity allowed TransAlta by the Board with the rate achieved on equity, Drs. Waters and Winter discovered that the rate achieved exceeded the rate allowed by an average gap of 12 basis points over 23 years. The maximum shortfall in any one year was 86 basis points.

Moreover, Drs. Waters and Winter noted that in no year did the achieved rate of return fall below the yield available on long Canadas. On a related basis, the gap between the allowed rate of

[260] Exhibit 162, p. 65
[261] U97065, p. 218.
[262] Exhibit 162, p. 28.

return and the long-term government bond rate can be viewed as a measure of the compensation, or premium, awarded by the Board for the risk that the achieved rate will fall below the government bond rate, as well as for long-term risk. Based on this criteria, TransAlta's history of returns demonstrates a very low exposure to regulatory risk.

With respect to the long-run business risk that arises from the possible development of low-cost substitutes to the electric power generated by TransAlta, the most significant risk to a GENCO is the possibility that the cost of gas-fired generators to larger customers will fall below the cost of electric power purchased from distributors. In general, the cost of generation of an electric generation utility is the parameter that determines its exposure to this risk, with high-cost generators being more exposed.

In the Alberta context, however, Drs. Waters and Winter argued that this risk is minimal. Alberta has among the lowest electricity prices in Canada. Specifically, TransAlta and AE rank as very low cost electric utilities and therefore face very low risk in terms of substitution risk. Also, Drs. Waters and Winter noted that existing generators have their fixed costs recovered separately from the power pool price. In contrast, this feature is not available to new generators.

Several factors could potentially contribute to an increase in business risk in the electric industry: the EU Act's overall impact on the business risk of the vertically integrated utility companies, the change in the regulatory regime in the industry, and the uncertainties associated with forecasting costs and outage rates over the longer time frames associated with the PPAs. However, Drs. Waters and Winter noted that these factors are balanced by increased opportunities to benefit from deregulation and by the substantial protection against increases in risks to utilities under the EU Act. Furthermore, it was noted that the EU Act will effectively shift risk away from the vertically integrated utilities, in part to municipally-owned distributors and in part to electricity users in the province.

Drs. Waters and Winter argued that to the extent that detailed aspects of the EU Act mechanisms are still to be resolved, both the history of fair treatment of utility shareholders in the province of Alberta as well as the protection provided by the EU Act can give assurance to shareholders that they will not be under-compensated for the risks that they bear. In addition, protection against major shocks to investors has been provided by the multiple tiers of oversight in the system (the Board, the Power Pool Council, the IAT, the Market Surveillance Administrator, and the TA).

As a result, the COCI recommended that the risk premium awarded to utility equity holders above the long-term interest rate not be increased beyond a level that is justified by the historical and current evidence on risk. The COCI also submitted that capital market evidence provides additional support for the proposition that long-term business risks have not increased among the investor-owned utilities. Consequently, the COCI used capital market evidence to derive a fair rate of return on equity.

Drs. Waters and Winter presented interest coverage ratios for a group of investor-owned utilities for the period 1990-1997, including energy transmission, electric, gas distribution and telephone utilities.[263] All of the companies were rated by DBRS. The average value for the AA group was 3.1 times, including 2.8 times for CUL and 3.4 times for TransAlta. For the same period, coverage ratios for the A group ranged between 1.6 and 3.7 times with a group mean of 2.5 times, while the companies in the BB rating ranged between 2.2 and 3.2 times with a group mean of 2.7 times. Drs. Waters and Winter also presented the interest coverage ratios for 11 electric and gas distribution utilities that are rated by DBRS (Evidence Table III-B). For the 1990-1997 period and the 1997 year, Drs. Waters and Winter confirmed that TransAlta had the highest interest coverage ratio of any non-telephone investor-owned utility in Canada.

With respect to TransAlta's application, Drs. Waters and Winter stated that the utility's applied-for return on equity of 10.65% and applied-for common equity ratio of 42% would result in interest coverage ratios of 3.4 times for 1999 and 3.5 times for the year 2000.

Drs. Waters and Winter argued that TransAlta's interest coverage ratio should improve over time as a result of lower interest rates in the future environment, relative to higher interest rates in the past. With respect to the future, they stated in their evidence that:

> TransAlta will be re-financing over half of its existing debt and preferred shares over the next five years, including $450 million during the 1999 to 2000 period. TransAlta's outstanding debentures have a weighted average cost of 8.9 percent as of December 31, 1997.[264] The refinancing of this debt at interest rates of less than 6.25 percent (based on a long Canada forecast of 5.5 percent and a spread in the order of 65 basis points[265]) will provide a very strong boost to TransAlta's interest coverage ratio.[266]

The COCI concluded that there is no justification for increasing the deemed equity component of the capital structure of the integrated utility to more than the 40% level found to be appropriate in Decision U97065. The COCI argued that TransAlta's evidence relating to business risk was unconvincing, providing only vague references to increased risk. This is particularly true given the consideration that TransAlta continues to have the highest bond rating of any Canadian utility. Furthermore, financeability has not been an issue in this proceeding and there is no suggestion that acceptance of the Waters/Winter recommendation would constrain TransAlta's access to low cost debt capital.

[263] Evidence, Table 9A and 9B
[264] TransAlta Utilities Corporation 1997 Annual Report, p.14.
[265] CIBC Wood Gundy, Corporate Debt Comments, January 23, 1999, p.10.
[266] Waters and Winter Evidence on Fair Return, p.60

Position of the FIRM Customers

The FIRM Customers supported the COCI's recommendation that TransAlta be allowed a book equity percentage of 35%, in comparison to its requested equity percentage of 42%. The FIRM Customers stated that Dr. Waters and Dr. Winter make a cogent case that, given past history, the Utilities' aggregate capital structure could contain less equity without greatly increasing financial risk. In particular, in recent years, the average book equity of TransAlta was about 38% and it was still a high-grade utility. At the very least, the FIRM Customers submitted that given that very little has changed since the last GTA, the Board should not allow an equity ratio in excess of the 40% equity ratio approved in the last GTA.

The FIRM Customers submitted that the Board correctly analyzed the sources and magnitude of risk by function in the 1996 GTA discussion. The FIRM Customers stated that, on balance, the risk of regulated generation has declined. However, volatility in the pool price, as a result of a tight supply-demand balance, has increased the amplitude of certain risks related to the pool price. The FIRM Customers responded that the correct way to deal with those risks is to establish deferral accounts for both the GENCO and DISCO.

The FIRM Customers submitted that generation risks in the near term are mitigated by legislative hedges between the GENCO and the DISCO. They have not changed materially since the 1996 GTA. In the longer-term, generation risks will be influenced by the PPAs between marketers and the GENCOs. The FIRM Customers stated that longer-term generation risks are slightly greater than current risks because of the indexing of costs and performance to benchmarks for up to 20 years. However, those longer-term risks are being taken into account by the IAT.

Position of ENMAX

ENMAX supported the COCI's recommended equity ratio of 35% for TransAlta. ENMAX stated that this recommendation is consistent with the lower end of Drs. Kolbe and Vilbert's range.[267]

ENMAX commented on TransAlta Corporation's April 1999 issuance of its Canadian Originated Preferred Securities. Notwithstanding the discussion at Tr. p.4171-4173 in the hearing and the response to ENMAX-TAU.22, regarding the Canadian Originated Preferred Securities, ENMAX argued that TransAlta waited until its argument to advise that some portion of the proceeds received from the issue of these securities will now be used in TransAlta Utilities. Also, ENMAX was concerned about comments provided by the utility in its argument (p.64) about the securities issue. ENMAX noted that although the investors will be getting 7.5% on an interest equivalent basis,[268] customers will have to pay a return on common equity plus tax on these same funds when they are invested in TransAlta Utilities by its parent.

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[267] Tr. p.4210
[268] Tr. p.4171

Position of IPPSA /SPPA

IPPSA/SPPA was critical of TransAlta's view of risk, particularly its argument that risk has increased across the board for the generation, transmission and distribution segments of its business. As a result, TransAlta requested a 2% increase in its common equity (from 40-42%) as a financial cushion to respond to the perception of increased business risk.

However, IPPSA/SPPA noted that when TransAlta was pressed to identify what aspect of deregulation will cause this increase in risk, Mr. Way, a TransAlta witness, could only say it is due to volatility regarding price and volume and deregulation.[269] When asked which of the three business segments (G, T & D) would face the higher risk, Mr. Way indicated he preferred to rely on Dr. Kolbe's evidence.[270]

Board Findings

With respect to the determination of an appropriate capital structure that is consistent with business risk, the Board considers that the following Board Findings set out in the Capital Structure section of Decision U97065 are still relevant for the current proceeding:

> The determination of an appropriate capital structure is a major factor in fixing the fair return component of the revenue requirement and, therefore, is particularly relevant to ratepayers. The Board, in this section, determines an appropriate capital structure to maintain the utility's total investment risk at a level that will allow the utility to raise debt and equity financing at a fair overall average cost to ratepayers. In other words, the appropriate capital structure should balance the interests of the utility's bondholders and shareholders with that of ratepayers and should produce the minimum cost of providing quality service consistent with preserving the financial viability of the utility. The capital structure should maintain the utility's financial integrity and allow the utility to continue attracting the capital required to fulfill its obligations to its customers.[271]
>
> The Board notes that the level of a utility's business risk generally determines the extent to which it can increase its financial risk so that the overall investment risk is in the range accepted by the common, preferred and bond markets. Increasing/decreasing the common equity in a utility's capital structure will decrease/increase the utility's financial risk and, therefore, the overall investment risk seen by the bondholders and shareholders. Given the particular business risks of a corporation, the Board considers it appropriate to make any necessary changes to the common equity ratio, rather than the equity rate of return, to achieve the desired investment risk. Using this approach, the allowed fair return to shareholders on a utility's common equity is the return commensurate with

[269] Tr. p.3068
[270] Tr. p.3073
[271] Decision U97065, p.228

rates of return earned by common equity exposed to similar generic investment risk.[272]

In terms of business risk, the Board notes that TransAlta, the COCI and IPCAA presented evidence on the issue of business risk for the integrated utility, addressing to what extent the risks may have changed since 1996. The Board also notes that there does not appear to be a consensus of views with respect to integrated utility risk, based on the arguments that were presented on the subject matter in the proceeding. For example, TransAlta submitted that there is greater overall business risk for the company in 1999 and 2000 and the Utility was concerned about uncertainty in the electric industry. In contrast, the COCI concluded that long-term business risks have not increased for the vertically-integrated utility companies.

The Board agrees with the COCI that there have been some inter-functional re-allocation of risk, which will lead to sector-specific capital structure recommendations. The transfer of risk as a result of the EU Act, particularly due to the transfer brought about by legislated hedges, has contributed to significant shifts in risk across the GENCO, TRANSCO and DISCO functions. A discussion of the reallocation of risk will be fully addressed in the Business Risk by Function section.

The Board notes that there was only limited definitive evidence on integrated risk presented by the parties. At the same time, the parties presented extensive evidence regarding the business risk of the three functions, as well as changes that are occurring with respect to risk within each of the functions. Thus, for the Board to determine to what extent the business risk of the integrated utility has changed since the implementation of the EU Act, it is necessary to draw on evidence relating to both integrated risk as well as business risk by function.

Based on the evidence, the Board agrees with the view that current GENCO risks have not materially changed from the 1996 GTA. At the same time, the Board accepts the FIRM Customers' argument that the longer-term GENCO risks will be slightly greater than current risks. A major reason for this conclusion is the higher risk that is attributable to the indexing of costs and performance to benchmarks for up to 20 years through the PPA process. Also, the Board notes the COCI argument that several factors could potentially increase business risk in the electric industry. For example, changes in the regulatory regime and uncertainties associated with forecasting costs and outage rates related to the PPAs could contribute to higher long-term risks. In general, the Board accepts TransAlta's statement that business risks are increasing as a result of industry deregulation and restructuring in Alberta, increased competition, a new regulatory framework and transitional uncertainties. However, to the extent that longer-term GENCO risks have increased, the Board notes these longer-term risks are presently under consideration in the IAT/PPA proceeding. As a result, the greatest weight should be placed on the evidence relating to the 1999-2000 period. Thus, the Board concludes that GENCO business risk is slightly higher relative to the 1996 risk level.

[272] Decision U97065, p.229

With respect to DISCO risk, the Board agrees with the argument that the longer-term post-2000 DISCO retail and brokerage risk is greater than the current risks, with present risks being representative of 1996 risks. Longer-term risks are greater as a result of the introduction of competition and customer choice. The Board notes that various parties such as the FIRM Customers and the COCI have addressed the potential for higher long-term risks in the retailing function, primarily as a result of new competition. These views have been presented in the DISCO Risk section. However, the Board notes that these risks will not manifest themselves during the 1999-2000 test period. As a result, for the purpose of assessing overall integrated risk, the Board concludes that DISCO risk is basically unchanged from 1996.

Finally, with respect to TRANSCO risks, the Board notes that there was universal agreement in the current proceeding that TRANSCO risk is low and relatively unchanged from 1996. Thus, all of the parties discussed various reasons for the low and relatively stable risks in the TRANSCO function. These views have been presented in the TRANSCO Risk section. Based on the evidence, the Board concludes that there has been no change to the level of TRANSCO risk during the test period relative to 1996.

In addressing the issue of business risk, the Board considers that it is appropriate to acknowledge longer-term risks as they relate to GENCO and DISCO risks since the electric industry is currently in the process of being restructured towards partial deregulation. Based on the Board's conclusions on the status of risks for the separate functions, combined with the consideration that some weight must be given to the longer-term risks, the Board concludes that business risks for the integrated utility have modestly increased since the 1996 GTA. Risks have increased relative to 1996 for several reasons.

First, there is greater uncertainty in the electric industry during the current transitional period toward deregulation. Second, the new proposed post-2000 regulatory framework represents a new environment for the electric industry and a major departure from the past regulatory environment. Related to this issue, the new framework has not yet been completed, with further processes and decisions to be made regarding the GENCO (the PPA regime), DISCO (the Distribution Tariff and the Regulated Rate Option), and the TRANSCO functions. Third, there is the potential for increased competition during and after the transitional period. Competition is presently starting in the GENCO sector, albeit at a modest level. With regard to the post-2000 period, significant new competition will commence in the DISCO retail sector in 2001.

However, the Board notes that it has mitigated a substantial amount of the modest increase in business risk of the integrated utility by shielding the utility from the volatility of hourly pool price changes through the implementation of pool price deferral accounts for both the GENCO and DISCO functions in the current proceeding. This shield was not available to the GENCO and DISCO functions in 1996. In comparison to the 1996 GTA period, volatility and hence risk of hourly pool prices has grown substantially. As a result, the Board is in agreement with the need for deferral accounts. Finally, the Board notes that it has instituted a deferral account for TRANSCO capital additions, which represents a further change from 1996. As a result of these

cumulative measures by the Board, integrated business risk has been reduced relative to the level of risk that would have been in place without any Board actions.

It should be noted that the impact of a deferral account on the business risk of an integrated utility is less than the impact of deferral accounts on the risk of a GENCO or a TRANSCO on a stand-alone basis. The reduced effect is related to the fact that there are diversification benefits characteristic to an integrated utility which tend to reduce the risk of the separate functions within the utility. Specifically, there are natural risk mitigants between the GENCO and the DISCO functions. For example, high pool prices represent a risk to the DISCO in terms of higher costs but they represent an offsetting benefit to the GENCO in terms of higher revenues. Thus, a deferral account would have less of an effect on the reduction in risk for an integrated utility, in comparison to the impact of a similar deferral account on the risk of a GENCO or a DISCO.

Accordingly, the Board considers on balance that there has only been a very slight increase in business risk for the integrated utility relative to 1996. The Board considers that this slight increase in risk would provide support for a considerably lower increase in TransAlta's common equity ratio in comparison to its requested 200 basis point (2%) increase to 42%.

The Board notes that TransAlta has confirmed that it is critical for the utility to maintain a high credit rating and avoid a downgrade since it has significant refinancing obligations in 1999 and 2000. As a result, TransAlta has undertaken a financing plan to maintain its AA rating. In this regard, the Board notes that according to TransAlta Utilities Corporation's 1998 Annual Report, the Utility has a heavy refinancing slate in 1999 and 2000, refinancing $320 million, or approximately 24% of its $1.34 billion in long-term debt (as of 31 December 1998).

Thus, based on the Board's assessment of business risk of the integrated company for 1999 and 2000, the Board has determined that an acceptable range of common equity ratios for TransAlta is in the range of 40-42%. This target range provides a mid-point of 41%, reflecting the slight increase in risk from 1996. This Board Decision in effect allows TransAlta to realize a higher common equity ratio in comparison to the utility's 40% ratio that was deemed by the Board in 1996. In addition, the Board notes that based on an allowed common equity ratio of 40-42% and an equity rate of return of 9.00-9.50% (determined in the Return on Equity section), TransAlta's before tax interest coverage will be 3.29-3.39 times for 1999 and 3.47-3.58 times for the year 2000. The Board observes that this coverage ratio is comfortably above the minimum interest coverage ratio of 3.0 times that is necessary to maintain a AA rating (DBRS) or a A+ rating (CBRS) in general. In addition, the Board notes COCI's argument that TransAlta's interest coverage ratio should improve over time as the utility refinances its debt at lower interest rates relative to the embedded cost of its debt. On an after-tax basis, TransAlta's interest coverage will be 2.11-2.16 times for 1999 and 2.15-2.20 times for the year 2000.

Accordingly, the Board considers that its determinations will allow TransAlta to maintain its current credit rating. In addition, the Board's determinations will allow TransAlta to attract capital for new construction and refinancing purposes on favourable terms.

Taking into consideration all of the above, the Board considers that the following integrated capital structure (i.e. investor supplied funds; excluding no-cost capital and contributions) for TransAlta will reflect the business and financial risks that are faced by the utility during the 1999-2000 period:

TransAlta Integrated Capital Structure

Board Approved

	Common Equity	Preferred Equity	Total Equity	Debt
TransAlta 1999-2000	40.0-42.0%	9.5%	49.5-51.5%	48.5-50.5%
Mid-point	41.0%	9.5%	50.5%	49.5%

Accordingly, the Board considers that an integrated common equity ratio of 40-42% is appropriate for TransAlta for the test years 1999 and 2000.

(2) Ranking of Business Risk By Function

Background

For the purpose of developing the detailed schedules in its Application and complying with the Board's directive to provide capital structures for each business unit, TransAlta has used a target capital structure of 42% common equity.[273] TransAlta stated its position as follows:

> TransAlta does not intend to establish a separate capital structure for each segmented business unit since, in its view, investors perceive the Company as one entity and evaluate their investment decisions accordingly. Additionally, each segmented business unit would lack the size individually to obtain as a high a credit rating and attract debt and equity capital at the rates which TransAlta can obtain. However, in response to the Board's request for such information, I have included in Appendix 1, Capital Structures for Segmented Business Units, our analysis of business risks, bond rating agency guidelines and indicative capital structure criteria for segmented business units.[274]

[273] Evidence of Marvin Waiand in Exhibit 13, Binder #2, Section 6.1
[274] Evidence of Marvin Waiand in Exhibit 13, Binder #2, Section 6.1

> Based on the above discussion overall, the target capital structures for each of TransAlta's business segments, if they were individually capitalized, would reflect the relationships shown above. However, in the absence of reasonable forecast data, particularly from resolution of PPA issues, it is TransAlta's position that it is still premature to allocate capital and that TransAlta's capital structure for each segmented business unit would be established at the same level as for the integrated utility as a whole. If these business units were to be capitalized as distinct legal entities, for practical purposes, the starting capital structures would be the same as the integrated utility and would be adjusted over time as financial track records became established and as investors, bankers and bond rating agencies became able to make judgments about the financial performance and financial stability of these businesses.[275]

Given the risk profile of the generation, transmission and distribution functions, TransAlta's witness, Dr. Kolbe established the ATWACC, common equity ratios, and return on common equity for 1999 using two methods as follows:

Method A	**ATWACC**	**Common Equity**	**Return on Common Equity**
Generation	6.75%	39.85%	10.84%
Transmission	6.25%	33.15%	10.84%
Distribution	8.00%	56.58%	10.84%
Weighted Average	6.91%	42.00%	10.84%

Method B	**ATWACC**	**Common Equity**	**Return on Common Equity**
Generation	6.75%	42.00%	10.45%
Transmission	6.25%	42.00%	9.26%
Distribution	8.00%	42.00%	13.43%
Weighted Average	6.91%	42.00%	10.84%

(Ref. Kolbe Rebuttal Evidence: Table no. ALK-2 Revised Panel A:1999)

EPGI submitted forecast capital structures of 46% common equity and 54% debt for 1999 and 48.8 % common equity and 51.2% debt for the year 2000. EPTI submitted forecast capital structures of 35.3% common equity and 64.7% debt for 1999 and 34.1% common equity and 65.9% debt for the year 2000. In Decision U97065, the Board approved EPI's requested capital structure of 34.8% common equity and 65.2%, with 0% held in terms of preferred equity.

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[275] Evidence of Marvin Waiand in Exhibit 13, Binder #2, Section 6.1 App 1.3

The COCI submitted that the sector-specific equity ratios for 1999 and 2000 should be set at 35.5% for TransAlta GENCO, 29% for TransAlta TRANSCO and 42% for TransAlta DISCO, given the risk profile of the generation, transmission and distribution functions.[276]

ENMAX submitted that based on the risk profile of the generation, transmission and distribution functions, it supported the COCI's recommended sector-specific equity ratios for TransAlta for 1999 and 2000. Accordingly, ENMAX recommended equity ratios of 35.5% for generation, 29% for transmission and 42% for distribution.

The FIRM Customers noted the overall positions of the three utilities with respect to relative risk and capital structure (percent of common equity ratio) by business function:

	TransAlta Application	TransAlta Difference From Integrated %	EPGI/EPTI 1999 Application	EPGI/EPTI 1999 Difference From Integrated %
Generation	39.9%	-2.1%	46.0%	1.2%
Transmission	33.2%	-8.8%	35.0%	-9.8%
Distribution	56.5%	14.5%	N/A	N/A
Integrated or Aggregate Request	42.0%		44.8% excluding distribution	

Source: Marcus Evidence, p.4

Position of TransAlta

Dr. Kolbe submitted his views of business risk in his direct testimony:

> From a first principles standpoint, I believe that the basic business risk of generation, legislated hedges aside, exceeds that of transmission and distribution. This is because generation has become more subject to economically viable competition than the other two functions (which is one of the major reasons North American power markets are becoming more competitive). Next highest in basic business risk is distribution, which has more opportunities for bypass and competitive pressure on margins than transmission. The lowest risk belongs to transmission, which must be operated as a single, integrated system.[277]

[276] Exhibit 162, p. 117

[277] Direct Evidence of Dr. Kolbe, p.47

Dr. Kolbe then adjusted the risk for the specific functions to acknowledge the differences in the Alberta market, particularly as a result of the transfer of risk from generation to distribution caused by the legislative hedges. Due to the transfer in risk, Dr. Kolbe recommended a downward adjustment of 1/2 percentage point in the generation cost of capital to 6 ¾% and an increase in the distribution cost of capital to 8%.

In summary, TransAlta submitted that assuming there is no transfer of risk, the ranking of business risk by function from highest to lowest is Generation followed by Distribution then Transmission. However, when the transfer of risk is included, TransAlta switched the order to Distribution being the highest risk followed by Generation then Transmission.

Position of EPGI/EPTI

Dr. Evans presented his relative business risk conclusions about the GENCO function in Table 3.1 of his evidence, summarizing the risks for the generation function of Edmonton Power in 1996, EPGI under the 1999/2000 GTA regime, EPGI under the PPA regime, gas pipelines, gas distributors and oil and products pipelines.[278] Dr. Evans concluded that the relative risk rankings presented from lowest to highest risk are gas pipelines (lowest risk), gas distributors, Edmonton Power generation in 1996, EPGI 1999/2000, oil/products pipelines and EPGI PPA (highest risk). EPGI 1999/2000 and oil/products pipelines were determined to be of similar risk. EPGI stated that no evidence contrary to that of Dr. Evans was cited on the matter of EPGI's business risks vis-à-vis those of other energy utilities or pipelines.

Based on his assessment of business risk about the TRANSCO function, Dr. Evans concluded:

- The business risks of EPTI are somewhat greater than the business risks of gas pipelines and somewhat less than the business risks of gas distributors.[279]

EPTI also submitted that there was essentially unanimous agreement among the experts that transmission is the least risky function of the Utilities.[280]

Given his comparison of the business risk of EPGI and EPTI relative to the business risk of other energy utilities and pipelines, Dr. Evans concluded that GENCO risk is greater than TRANSCO risk.

[278] Exhibit 4, p.41
[279] Exhibit 4, p.45
[280] Exhibit 4, p.46; ENMAX.EPGI-22(d), p.4; Exhibit 162, p.3; Exhibit 158, p.4; Tr. p.5206; Exhibit 13, Volume 2, Appendix 4, p.47, 50-51

Position of the Intervenors

Position of COCI

In terms of an assessment of the business risks of the transmission function relative to the business risks of generation, Drs. Waters and Winter expressed the view that transmission risks are less than 90% of the risks of generation assets, due to various risk protection factors. As a lower bound, transmission risks are more than 60% as risky as generation in light of the risk protection factors in place for generation. Drs. Waters and Winter further commented that the specifics of the final PPA design will ultimately determine the level of the relative risk factor within the range of 60 to 90%.

In terms of an assessment of the overall distribution risks relative to generation risks, Drs. Waters and Winter submitted that the distribution wires function is less risky than generation. In contrast, distribution retailing is substantially more risky than generation assets, largely as a result of the transfer of risks from the generation to the distribution sector. In summary, Drs. Waters and Winter stated that a reasonable estimate of the relative risks is that the combined distribution functions are 10 to 40% more risky than generation assets.

Based on its evidence, the COCI submitted that the ranking of business risk by function, in order from highest to lowest, is Distribution followed by Generation then Transmission.

Position of IPCAA

IPCAA submitted that in terms of business risk, DISCO risk is greater than TRANSCO risk. In addition, in his evidence on behalf of IPCAA, Mr. Drazen recommended equity rates of return of 8.3% for GENCO, 8.0% for DISCO and 7.7% for TRANSCO, thereby suggesting a similar risk ranking.

IPCAA submitted that the TRANSCO is the least risky function. In support of this statement, IPCAA noted that there is no revenue variation since the TRANSCO's costs are recovered by a guaranteed annual payment from the TA. In addition, while the actual costs may vary from projected costs, the majority of the TRANSCO's costs are comprised of return, income taxes and depreciation. For example, capital-related costs for TransAlta-TRANSCO represent 77% of proposed total 1999 costs, whereas for EPTI capital-related costs represent 67% of 1999 costs.

IPCAA argued that the risk for DISCO-Wires is somewhat higher than that for transmission. In support of this statement, IPCAA stated that the DISCO does not have a guaranteed revenue payment, but instead depends on the number of customers and their usage. At the same time, this risk can be reduced by recovering a larger portion of the Wires cost through fixed monthly charges (as AE-DISCO and TransAlta-DISCO have proposed in their recent Phase II filings). IPCAA also noted that DISCO-Wires have a higher proportion of their cost of service in operating costs as opposed to capital-related costs, resulting in higher potential risks since actual costs may vary from projected costs. For example, operating costs for TransAlta-DISCO represent 35% of proposed total 1999 costs.

IPCAA submitted that DISCO retailing has the highest risk. IPCAA explained this arises from the fact that the DISCO incurs a high fixed cost (primarily Reservation Payments), which is recovered on a variable basis (depending on the rate design) from customers. In addition, to the extent the DISCO has unhedged load, the DISCO's retailing function is subject to forecast risk related to Pool Price. However, IPCAA stated that this risk can be mitigated by deferral accounts and Pool Price flow-through rates. With regard to this recommendation, IPCAA noted that a deferral account on unhedged energy was used by TransAlta-DISCO in the 1998 Negotiated Settlement.

Position of the FIRM Customers

The FIRM Customers noted TransAlta's argument that Generation is less risky than the average cost of capital. TransAlta's witness Dr. Kolbe claimed that the main source of risk is the system of legislated hedges. As a result, Dr. Kolbe adjusted costs of capital by function to acknowledge the transfer of risk from Generation to Distribution.

In contrast to TransAlta's views, the FIRM Customers noted EPGI's argument that the difference in risk by function between Generation and Transmission is large. Thus, EPGI argued that Generation is considerably more risky than Transmission. As a result, EPGI concluded that generation is more risky than the average cost of capital, which conflicts with TransAlta's argument.

The FIRM Customers submitted that on a theoretical basis, TransAlta and EPGI cannot be both correct at the same time. The two utilities have adopted very diverse positions with respect to the riskiness of Generation. As a result, the FIRM Customers concluded that the Board will not be able to adopt both TransAlta and EPGI's positions with regard to GENCO risk, since the views of the two parties are entirely different.

The FIRM Customers concluded that both TransAlta and EPGI could be wrong in terms of their assessment of risk and the relative ranking of risk by function. A more moderate position would be to view DISCO and GENCO risk as being on an equivalent basis, with TRANSCO risk being the lowest of the three functions (similar to AE's relative ranking).

Board Findings

The Board agrees with TransAlta and the COCI that the DISCO risk is currently greater than the GENCO risk due to the transfer of risk and the higher variance in revenues for the DISCO function in comparison to the GENCO function. To the extent that investors consider risks beyond the test years, the DISCO function will clearly be more risky than the GENCO function as a result of the brokerage and retailing functions required to be carried out by the DISCO in the provision of the Regulated Rate Option.

The Board notes that EPGI/EPTI considered that the GENCO function was more risky than the TRANSCO function. The Board also notes that TransAlta and the COCI agreed that the ranking of risk by function from highest to lowest is DISCO, GENCO and TRANSCO.

In contrast, based on IPCAA's evidence, the Board concludes that IPCAA's risk ranking would be GENCO, DISCO and TRANSCO.

An alternative view was presented by Mr. Marcus in his evidence on behalf of the FIRM Customers.[281] Mr. Marcus suggested that it was more likely to be correct to view DISCO and GENCO risk as being equal with TRANSCO being the least risky.

Considering all of the above, the Board considers that the appropriate ranking of business risk by function from highest to lowest is DISCO, GENCO and TRANSCO.

(3) GENCO Risk and Capital Structure

Position of TransAlta

Dr. A. L. Kolbe provided evidence for TransAlta on the differential risk by function. In terms of a starting value, he adopted Dr. Vilbert's estimate of a base 7% ATWACC. In Dr. Kolbe's opinion, the total risk of the unbundled units must be equal to the total risk of the bundled utility, since the risk of the industry is unchanged by the act of unbundling the cost of capital.

In terms of estimates of the relative costs of capital for TransAlta's lines of business, Dr. Kolbe stated:

> Given the scarcity of relevant data and the fact that the lines of business remain part of an integrated company subject to a number of common risk factors, I believe only modest adjustments should be made for basic line of business risks (i.e., ignoring legislated hedges and the like). I recommend an after-tax weighted-average cost of capital for generation that is 1/4 percentage point higher than the bundled utility value of 7 percent estimated by Dr. Vilbert, an after-tax weighted-average cost of capital for transmission that is 1/2 percentage points lower, and an after-tax weighted-average cost of capital for distribution that is equal to Dr. Vilbert's.[282]

Dr. Kolbe confirmed that these relative risk conclusions are generally supported by data from the U.K., based on the manner in which the U.K. generation companies are believed to have operated.

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[281] Marcus Evidence, p.4
[282] Direct Evidence of Dr. Kolbe, p.47

Thus, as a starting point, Dr. Kolbe estimated an ATWACC for the Generation function of 7¼%, 7% for Distribution and 6½% for Transmission. Dr. Kolbe then adjusted these values to acknowledge the differences in the Alberta market. Specifically, he adjusted the rates for generation and distribution, based on the transfer of risk from generation to distribution caused by the legislated hedges. As a result of the transfer in risk, Dr. Kolbe recommended a downward adjustment of 1/2 percentage point in the generation cost of capital to 6¾% and an increase in the distribution cost of capital by a full percentage point to 8%. Finally, due to the new flow-through account available to the TA for transmission services, Dr. Kolbe concluded that the transmission cost of capital should be reduced by 1/4 percentage point to 6¼%. These ATWACC percentages translate into common equity ratios of 39.85% for GENCO, 33.15% for TRANSCO and 56.58% for DISCO, assuming an integrated utility common equity percentage of 42% and a constant cost of equity across the lines of business.[283]

TransAlta conceded that it is open to debate as to how much of an adjustment should be made to reflect the risk transfer from the Generation to the Distribution function as a result of legislated hedges. Based on the extremely tight electric market in the near term, Dr. Kolbe's rebuttal testimony presented lower estimates for the risk transfer. The evidence in the rebuttal testimony indicated that the risk transfer may be as low as a 0.25% risk reduction for Generation and a 0.50% risk increase for Distribution, (i.e., a 7% ATWACC for Generation and 7.5% ATWACC for Distribution), in comparison to the long-term impact of 0.50% risk reduction for generation and 1.0% risk increase for Distribution. At the same time, Dr. Kolbe submitted that it is not possible that the near-term risk transfer is zero.

TransAlta argued that if the FIRM Customers' recommendation, as presented by Mr. Marcus, is used to calculate the long run direction of the cost of capital trend as a tie-breaker, then the Board should use 6.75% for Generation and 8.0% for Distribution. The rationale for TransAlta's recommendation is that unbundling and partial deregulation is contributing to an increase in the cost of capital for all parts of the previously integrated, regulated utility.[284]

TransAlta was critical of the FIRM Customers' argument regarding GENCO risk. The FIRM Customers, relying on Drs. Waters and Winter, argued that the GENCO risk is particularly low for TransAlta and stated that the IAT process contains little risk for TransAlta. Thus, according to the FIRM Customers, until the IAT process has been completed, the risks attendant on the IAT process are a matter of speculation. However, TransAlta argued that uncertainty related to the IAT process is in general generating risk.

Whereas the FIRM Customers argued that nothing has changed regarding line-of-business risk since 1996, TransAlta confirmed that the FIRM Customers discussed at least one change in risk. Specifically, the FIRM Customers stated that the volatility in pool prices has increased the amplitude of certain risks related to the pool price. The FIRM Customers further stated that this risk necessitates a whole new deferral account. Since the only reason to establish a new deferral

[283] Ref. Table No. ALK-2 Revised Panel A:1999
[284] Tr. p.5129

account would be to mitigate new risks, TransAlta responded that the FIRM Customers' argument demonstrates the need for a revised analysis of relative risk.

TransAlta submitted that the relevant issue for line-of-business cost of capital risk is the assessment of risk relative to the benchmark integrated utilities used by the parties to estimate the cost of capital. Through the testimony of Dr. Kolbe, TransAlta has analyzed those risks to the extent possible. While the absence of a large sample of publicly traded "pure plays" in each of Alberta's uniquely organized lines of business makes this analysis a matter of some judgment, TransAlta submitted that the FIRM Customers' arguments provide no reason to deviate from Dr. Kolbe's judgment in this matter.

TransAlta noted that while the FIRM Customers acknowledged that Generation risks are mitigated by the legislated hedges, it did not propose an adjustment to the Generation cost of capital. Instead, the FIRM Customers argued that Dr. Kolbe's adjustment from Generation to Distribution is too much. In addition, the FIRM Customers argued that TransAlta's Generation is of particularly low risk, since it is low-cost and not subject to stranded-cost risk.

TransAlta responded that Dr. Kolbe explained that risks such as stranded costs primarily affect whether the utility has a fair opportunity to earn the cost of capital, not the magnitude of the cost of capital itself.[285] Dr. Kolbe further explained that TransAlta's low-cost Generation does not benefit as much from the legislated hedges as do other Utilities' Generation, while its Distribution function bears a full pro-rata share of the risks of the other generators in the Province.[286] Consequently, TransAlta argued that its Generation function should receive less of a reduction in its line-of-business cost of capital than Dr. Kolbe proposes.

TransAlta was critical of the COCI's argument against Dr. Kolbe for suggesting that the long-term risk profile should be used as a tie-breaker to determine the allocation of risk during the 1999/2000 period.[287] TransAlta submitted that both Drs. Kolbe and Vilbert testified that the risks in the 1999/2000 period are the appropriate risks to consider. Thus, the longer-term view is only appropriate when it is required as a tie-breaker. For this reason, TransAlta argued that the COCI's list of five risk reduction factors for the Utilities should not be given much weight. The reductions discussed by the COCI apply to the post-2000 period, and not the 1999/2000 period for which rates in the current proceeding are being set. TransAlta concluded that to the extent possible, the allowed cost of capital should reflect the risks of the period corresponding to the time frame the rates are to be in effect. Otherwise, shareholders would be over or under compensated if the cost of capital were based upon risks for a subsequent period.

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[285] Section III of Dr. Kolbe's Rebuttal Testimony
[286] Section IV, Part B of his Rebuttal Testimony
[287] COCI Argument, p.11

Position of EPGI

EPGI requested that Dr. Robert Evans develop a range of capital structure values consistent with its long-term business risks. EPGI's submitted that its forecast capital structures are consistent with Dr. Evans' recommendations. The forecast actual capital structures of EPGI for 1999 and 2000 are:[288]

	1999	2000
Debt	54.00%	51.2%
Common Equity	46.00%	48.8%

EPGI has requested approval of these forecast actual capital structures for the purpose of weighting the costs of debt and common equity to arrive at a fair rate of return. EPGI confirmed that the requested capital structures are forecast actual capital structures and not deemed capital structures. During cross-examination, Dr. Evans stated that the 46% common equity ratio represents the actual dollars that the company has put into EPGI. Dr. Evans further responded that:

> What I'm suggesting is that the Board should accept the capital structure as created by EPGI's shareholder unless that actual capital structure falls outside the range of what is reasonable in light of the business risks, and that approach is consistent with what you have done with the ATCO Gas companies and others. It is consistent with what you did in the 1996 decision, as I understand it. At that time, you used the actual capital structure for APL and Edmonton Power. With respect to TransAlta, the feeling of your Board was that 40 percent was the maximum equity ratio, and TransAlta had, I believe 42 and a fraction, so you said, We will make a determination based on 40. But with respect to Edmonton Power and APL, you accepted the management capital structure, the actual forecast, because the feeling was that it did not exceed the 40 percent. So I'm basically saying that I think we should do the same thing here.[289]

In Decision U97065, the Board awarded Edmonton Power a rate of return on rate base assuming a 34.8% common equity ratio, a 65.2 % debt ratio and 0% held in terms of preferred equity.[290] As a starting point, EPGI argued that the Board should reject any suggestion that the 34.8% common equity ratio should form a point of departure for determination of the appropriate common equity ratio in 1999/2000. First, Edmonton Power's expert evidence in the 1996 hearing recommended that the company should be permitted to increase its common equity ratio to 45-50%.[291] Second, the 34.8% common equity ratio was awarded for the integrated

[288] Exhibit 2, p.19
[289] Tr. p.4840-4841
[290] Decision U97065, p.231
[291] Exhibit 39, p.23-24

operations of EPI.[292] In contrast, EPGI's capital structure is intended to capture the stand-alone risks of the generation business and is consistent with the Board's directive from Decision U97065 that separate capital structures by function be considered in this proceeding. Third, the Board concluded in Decision U97065 that common equity ratios up to 40% could be justified on the basis of the business risks of integrated utilities as they existed in 1996.

Consistent with the Board's directive in Decision U97065, Dr. Evans considered the "stand-alone" business risks of EPGI for the purpose of determining a reasonable range of stand-alone generation capital structure ratios. Dr. Evans stated:

> Those who use the services and facilities of EPGI and EPTI should pay rates that reflect the costs of providing those services and facilities independent of the other activities of EPCOR, its shareholder or each other. This proposition is known as the "stand alone principle."[293]

Dr. Evans also noted that:

> A risk evaluation or rate of return analysis which 'looked through' EPCOR to the City of Edmonton would be a violation of the stand-alone principle.[294]

EPGI stated that the propriety of "looking through" to the City of Edmonton was rejected by the Board in Decision E87100.[295] As a result, EPGI submitted that the Board should continue to reject any such suggestion.

In addressing the question of business risk, EPGI submitted that there should be a range of reasonable capital structure ratios dictated by the business risks to which EPGI is exposed.[296] EPGI further submitted that the range of capital structure ratios should be determined by reference to the long-run business risks perceived by investors, and should not be constrained by the limits of a test period for regulatory purposes.[297] Thus, in the present circumstance, EPGI argued that the Board should consider not only the business risks that EPGI will face during the 1999/2000 test period, but also the business risks that EPGI will face during the PPA period.[298]

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[292] Decision U97065, p.231
[293] Exhibit 4, p.22
[294] Exhibit 4, p.23
[295] p.38
[296] Exhibit 4, p.47-48
[297] Exhibit 4, p.26
[298] Tr. p.4806-4819

In regard to this view, Ms. M. T. McLeod, EPGI's capital markets expert, stated:

> From the perspective of a capital markets participant, the key determinant of the business risks of EPTI and EPGI is the operating environment which will exist for the Alberta electric industry under the Electric Utilities Act ("EUA"). For the transmission companies, the future operating environment will not be materially different than that which has existed historically. For the generation companies, however, the future operating environment will be fundamentally altered by the Power Purchase Agreements ("PPAs") which will set out the contractual rights and obligations of the various owners and buyers.[299]

EPGI noted that the business risk analysis of Drs. Waters and Winter in respect of AE and TransAlta focused almost entirely on the risks faced by these companies under the PPA regime. As Drs. Waters and Winter stated:

> The EUA has two relevant stages: the EUA as enacted in 1995 will continue to be in force in 1999 and 2000. The EUA as amended in 1998 will come into force in 2001… Our focus on the change in long run risks is consistent with equity investors having long run investment horizons.[300]

In summary, EPGI concluded that Dr. Evans and Ms. McLeod (representing EPGI), Mr. Falconer (TransAlta), Dr. Waters and Dr. Winter (COCI) and Mr. Marcus (the FIRM Customers) all agree, as a matter of principle, that the Board should determine its capital structure and rate of return findings based on an examination of long-run business risks. In this context, long-run business risks for generation include not only the current GTA regime, but also the PPA regime that will prevail in the post-2000 generation sector.

Dr. Evans' business risk analysis gave consideration to the following areas:

- the business risks of EPGI assuming a continuation of the GTA regulatory regime in place for the 1999/2000 test period;
- the business risks of EPGI under the PPA regime;
- a comparison of EPGI's business risks under the GTA/PPA regimes with the business risks faced by Edmonton Power's generation function at the time of the 1996 GTA; and
- a comparison of EPGI's business risks under the GTA/PPA regimes with the business risks faced by other energy utilities and pipelines.

The individual aspects of business risk examined by Dr. Evans in his comparison with 1996 risks included: diversification risks and benefits, pool price risk, expense forecast risk in 1999/2000,

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[299] ENMAX.EPGI-22(d), p.3
[300] Exhibit 162, p.28

cost indexing risk in the PPA period, changes to power pool rules, availability forecasting risk and regulatory risks.[301]

Based on his business risk analysis, Dr. Evans concluded that the 1999/2000 business risks are significantly higher than the business risks that existed in 1996.[302] Analyzing the business risks, Ms. McLeod also concluded:

> In my opinion, the prospective PPA regime, on balance, exposes the generation companies to greater business risk than has existed historically due to the 20-year term of the agreements, a period during which no regulatory review or renegotiation of contract terms is contemplated. As a result, the generation companies will be exposed to greater cost recovery risk than has historically existed, with the likelihood that earnings will be materially more variable than in the past.[303]

As a result, EPGI concluded that its long-run business risks are greater than the business risks of Edmonton Power's Generation function in 1996.

In his comparison with the business risks of other energy utilities and pipelines, the individual aspects of business risk that Dr. Evans examined included: long-run capital recovery risk, operating leverage risk, ability to change rates in response to changing forecast costs, ability to change rates in response to changing forecast sales, sensitivity of revenues to sales, deferral accounts, competitive risks, diversification risks/benefits and regulatory risks.[304]

Based on his analysis of the business risks of the generation function in comparison to the business risks of other energy utilities and pipelines, Dr. Evans concluded that EPGI's total business risks are greater than the total business risks of either gas distributors or gas pipelines. In addition, EPGI's total business risks are not dissimilar to those of oil and products pipelines.[305]

Dr. Evans presented his relative business risk conclusions in Table 3.1 of his evidence, summarizing the risks for the Generation function of Edmonton Power in 1996, EPGI under the 1999/2000 GTA regime, EPGI under the PPA regime, gas pipelines, gas distributors and oil and products pipelines.[306] The relative risk rankings presented from lowest to highest risk are gas pipelines, gas distributors, Edmonton Power generation in 1996, EPGI 1999/2000, oil/products pipelines and EPGI PPA. EPGI 1999/2000 and oil/products pipelines were determined to be of

[301] Exhibit 4, p.26
[302] Exhibit 4, p.31
[303] ENMAX.EPGI-22(d), p.4
[304] Exhibit 4, p.33
[305] Exhibit 4, p.40
[306] Exhibit 4, p.41

similar risk. EPGI stated that no evidence contrary to that of Dr. Evans was cited on the matter of EPGI's business risks vis-à-vis those of other energy utilities or pipelines.

EPGI submitted that the Board should focus on whether the business risks of EPGI are sufficient to justify the forecast actual common equity ratios. Based on Dr. Evans' risk assessment, the capital structure ratios approved by the National Energy Board in respect of oil and products pipelines contain common equity ratios of 45-50% and debt ratios of 50-55%.[307] Therefore, Dr. Evans concluded that a 45-50% common equity ratio range is appropriate in light of the business risks to which EPGI is exposed.[308] Ms. McLeod agreed with Dr. Evans' assessment of the prospective business risks of EPGI and the appropriate common equity ratio for the 1999 and 2000 test years.[309]

EPGI concluded that the 1999 and 2000 forecast actual common equity ratios fall within the 45-50% range. Thus, EPGI therefore submitted that the Board should use the forecast actual common equity ratios to determine the 1999 and 2000 rates of return on rate base for EPGI.

EPGI stated that it did not believe that any intervenor had taken issue with the reasonableness of its forecast actual capital structure ratios. EPGI noted that as a result of the similarity between its debt and equity costs, Mr. Marcus, representing the FIRM Customers, stated that he would "…be willing to accept Edmonton Power's capital structure for purposes of this case, as long as the Board indicates that it is not a precedent for any future analysis, either by this Board or through the IAT process."[310]

EPGI confirmed that Drs. Waters and Winter did not provide a capital structure recommendation in respect of EPGI, because their "analysis is based on capital market evidence and as such is applicable to TransAlta and ATCO, but not to the Edmonton Power utilities."[311] However, Dr. Waters did prepare a 1996 report on the appropriate capital structure and fair rate of return for the transmission operations of the City of Calgary Electric System (CCES Report). The CCES Report was filed in response to an information request in this proceeding.[312]

EPGI drew several observations and conclusions from the CCES Report.

First, similar to EPGI's status, Dr. Waters noted that the absence of preferred share capital and the status of CCES as a non-taxable entity caused the financial circumstances of CCES to differ from that of investor-owned, taxable Utilities.[313] Second, Dr. Waters recommended a deemed

[307] Exhibit 4, p.50-51
[308] Exhibit 4, p.51
[309] ENMAX.EPGI-22(d), p.5
[310] Tr. p.5212-5213
[311] Exhibit 162, p.2
[312] EPGI/EPTI.ENMAX-8
[313] EPGI/EPTI.ENMAX-8, CCES Report, p.1-2

capital structure for the Transmission function of CCES, amounting to 47.5% common equity, 39.2% debt and 13.3% contributions in aid of construction.[314]

Third, given the universal agreement among the applicants and the experts that the risks of the Generation function are greater than the risks of the Transmission function, then a higher common equity ratio is required in respect of the generation function. EPGI noted that 1999 and 2000 forecast actual common equity ratios are not materially different from the 47.5% Transmission function common equity ratio recommended by Dr. Waters in respect of CCES. EPGI speculated that had Drs. Waters undertaken a similar study in the current proceeding, he would likely have concluded that the forecast actual common equity ratios for EPGI were insufficient in light of EPGI's business risks.

Fourth, Dr. Waters' 47.5% common equity ratio recommendation in the CCES Report stemmed, in large part, from his analysis of coverage ratios. Noting the impact of Calgary's non-taxable status on its pre-tax interest coverage, Dr. Waters concluded that a 47.5% common equity ratio for the CCES Transmission business was required in order to maintain a reasonable balance in respect of the coverage ratios of AE and TransAlta.[315]

Depending on the common equity rate of return, the CCES coverage ratio using a 47.5% common equity ratio was in the range of 2.3-2.5x.[316] Of interest, Dr. Waters specifically rejected the use of a 40.0% common equity ratio for the CCES Transmission business, noting that such a ratio would have produced interest coverage values of only 1.9-2.1x.[317]

EPGI stated that the coverage ratios resulting from its requested 11.0% common equity rate of return and forecast actual capital structures would be 1.9-2.0x.[318] However, EPGI noted that if an 8.25% rate of return on common equity were adopted by the Board, consistent with the recommendations of Drs. Waters and Winter, then EPGI's interest coverage ratios would be very low at 1.7-1.8x.[319]

In light of the similarities between EPGI and EPTI and CCES (no preferred shares, non-taxable status and similar embedded debt costs), EPGI and EPTI argued that had Drs. Waters and Winter examined the interest coverage ratios of EPGI/EPTI for 1999/2000, they may have concluded that the combination of the forecast actual common equity ratios and applied-for rates of return on common equity were not unreasonable. For example, the highest interest coverage value using the applied-for rates of return and capital structures for either EPGI or EPTI is the 2.0x value for EPGI in 2000. The 2.0x value is less than the 2.3-2.5x range of coverage values

[314] EPGI/EPTI.ENMAX-8, CCES Report, p.8-9
[315] EPGI/EPTI.ENMAX-8, CCES Report, p.8-9
[316] EPGI/EPTI.ENMAX-8, CCES Report, Table 2B, p.7
[317] EPGI/EPTI.ENMAX-8, CCES Report, Table 2B, p.7
[318] Exhibit 39, p.4
[319] Exhibit 39, p.4

implicit in Dr. Waters' 1996 capital structure recommendation for the CCES. The 2.0x value is also similar to the 1.9-2.1x coverage values for CCES that were rejected by Dr. Waters as insufficient to maintain a proper "balance" between the coverage ratios of the investor-owned utilities.[320]

EPGI raised a concern that some parties may invite the Board to use the appropriate common equity ratios for AE and TransAlta as benchmarks for developing a range of appropriate common equity ratios for EPGI. EPGI argued that there are several reasons against using the equity ratios of AE or TransAlta as benchmarks. First, the capital structures of EPGI and AE /TransAlta are not comparable, because EPGI has no preferred shares. Given the presence of preferred shares in the AE/TransAlta capital structures, EPGI will have a higher debt ratio for a given common equity ratio and therefore greater financial risk than either AE or TransAlta.[321]

Second, interest coverage ratios represent an alternative measure of financial risk.[322] Since EPGI is currently not taxable and does not collect income taxes from its customers, EPGI's pre-tax interest coverage is adversely affected since an income tax "cushion" is unavailable to pay bond interest charges.[323] This situation results in a lower coverage ratio than would normally be the case if the utility was taxable. As a result, for a given common equity ratio, EPGI is exposed to greater financial risk than either AE or TransAlta.

Third, the ratings by the CBRS confirm that EPGI is exposed to greater risks than either AE or TransAlta. The CBRS awarded EPGI a B++ long-term debt rating, whereas the rating agency rated AE and TransAlta's long-term debt as both A+.[324]

As a summary, EPGI stated that the Board needs to recognize that EPGI's B++ bond rating is based on the assumption that the Board will accept the forecast actual capital structures contained in EPGI's application.[325] Related to this consideration, Ms. McLeod characterized the bond rating difference between EPGI and AE/TransAlta as a "very, very substantial discrepancy."[326] Ms. McLeod further stated that the CBRS has factored into its B++ bond rating the "ratification of the company's application with respect to capital structure."[327]

In response to cross examination, Ms. McLeod explained the impact of a B++ (or BBB) rating on EPGI's ability to raise capital. There is a very limited market in Canada for any issuer with a BBB rating. The entire BBB market in Canada comprises about 4% of all outstanding bonds. In

[320] Exhibit 39, p.7
[321] ENMAX.EPGI-22(d), p.4
[322] Exhibit 4, p.21
[323] ENMAX.EPGI-22(d), p.4; and Tr. p.4860-4862
[324] ENMAX.EPGI-25(b); EPGI/EPTI.ENMAX-20, Attachment D, p.1
[325] Tr. p.4874
[326] Tr. p.4859
[327] Tr. p.4874

addition, a substantial portion of the total institutions that buy debt will simply not buy anything rated below an "A", for reasons of policy or practice. Also, Ms. McLeod stated that companies that are rated BBB, high or otherwise, tend to be smaller companies, which means they issue less debt at a time. As a result, the BBB issuing market is illiquid and represents a very marginal market.

Ms. McLeod stated that EPGI is a rarity in that it is a mid-BBB rating. All Canadian companies that fall into the BBB category are at the high end of the rating. Thus, EPGI represents a new name to the market. In addition, there is considerable amount of uncertainty with respect to the development of this market. Ms. McLeod confirmed that the spreads for EPGI would be in the 125 basis points or higher range even in the improved environment in the current period.. As a result, it would be expensive and difficult for the company to issue debt.

Ms. McLeod emphasized that it will be imperative for EPGI to work its way towards becoming an A-credit over the next two years since the Utility currently represents a marginal credit and the minimum standard of corporate credit worthiness in Canada is in the "A" rating category. In order to accomplish this task, the Utility will have to both increase its common equity ratio and at the same time deal with its tax status, with the result that it may achieve a rating that is in the lower end of the "A" category.[328]

In summary, it was argued that EPGI's B++ bond rating reflects the applied-for capital structure ratios. EPGI faces a considerable challenge in raising debt on reasonable terms with a B++ bond rating. This challenge exists in both absolute and relative terms vis-à-vis the capital-raising capacities of AE and TransAlta. Consequently, EPGI submitted that the Board should accept the forecast actual capital structures of EPGI as reasonable for 1999/2000.

In consideration of the alternative, EPGI concluded that if the Board were to deem greater amounts of debt in the EPGI capital structure, then EPGI's existing bond rating would be placed in jeopardy, and further doubt would be cast on its ability to raise capital on reasonable terms and conditions.

Position of the Intervenors

Position of the FIRM Customers

The FIRM Customers submitted that the Board correctly analyzed the sources and magnitude of risk by function in the 1996 GTA discussion. The FIRM Customers stated that, on balance, the risk of regulated generation has declined. In addition, volatility in the pool price, as a result of a tight supply-demand balance, has not changed the types of risk faced by the Utilities. However, it has increased the amplitude of certain risks related to the pool price. The FIRM Customers responded that the correct way to deal with those risks is to establish deferral accounts for both the GENCO and DISCO.

[328] Tr. p.4868-4870

The FIRM Customers submitted that generation risks in the near term are mitigated by legislative hedges between the GENCO and the DISCO. They have not changed materially since the 1996 GTA. In addition, GENCO business risks are particularly low for TransAlta as a result of its depreciated plants and low fuel costs. Thus, TransAlta faces little risk from stranded costs.[329]

In the longer-term, generation risks will be influenced by the PPAs between marketers and the GENCOs. The FIRM Customers stated that longer-term generation risks are slightly greater than current risks because of the indexing of costs and performance to benchmarks for up to 20 years. However, those longer-term risks are being taken into account by the IAT. The FIRM Customers commented that the only residual risk left for the Board to consider is the risk that the IAT will under-compensate or over-compensate investors for those longer-term risks. In response to this issue, the FIRM Customers stated that it is speculative and represents a second-order impact.[330] In addition, the FIRM Customers noted that Drs. Waters and Winter provided significant detail regarding the IAT process, concluding that the process is unlikely to pose significant risks to shareholders.[331]

The FIRM Customers noted TransAlta's argument that Generation is less risky than the average cost of capital. TransAlta's witness Dr. Kolbe claimed that the main source of risk is the system of legislated hedges. As a result, Dr. Kolbe adjusted costs of capital by function to acknowledge the transfer of risk from Generation to Distribution.

In contrast to TransAlta's views, the FIRM Customers noted EPGI's argument that the difference in risk by function between Generation and Transmission is large. Thus, EPGI argued that Generation is considerably more risky than Transmission. As a result, EPGI concluded that Generation is more risky than the average cost of capital, which conflicts with TransAlta's argument.

The FIRM Customers submitted that on a theoretical basis, TransAlta and EPGI cannot be both correct at the same time. The two utilities have adopted very diverse positions with respect to the riskiness of Generation. As a result, the FIRM Customers concluded that the Board will not be able to adopt both TransAlta and EPGI's positions with regard to GENCO risk, since the views of the two parties are entirely different.

The FIRM Customers did not support the proposed capital structure requested by EPGI and EPTI.[332] However, the FIRM Customers did not believe the proposed capital structure would have a material effect on the costs and rates for either EPGI or EPTI in the 1999-2000 period. Unlike TransAlta, the costs of debt and equity are similar for both functions. In addition, the FIRM Customers also noted that neither EPGI nor EPTI will be paying income taxes during this

[329] Exhibit 162, p.48
[330] Exhibit 162, p.33
[331] Exhibit 162, p.28-38
[332] Exhibit 159, p.20

two-year time frame. Therefore, the FIRM Customers submitted that the Board could adopt EPGI/EPTI's requested capital structure with the proviso it would not consider that such a ruling sets a precedent for future proceedings.

Position of COCI

The COCI discussed its views on generation risk under the EU Act. Since costs must be projected on a long-term basis, the COCI stated that the PPA system will result in greater uncertainty in the difference between compensation to generation assets and the costs of production related to those assets. Under rate of return regulation, the prices charged by utilities are re-calibrated to costs on a periodic basis. In contrast, under the PPAs, the variable cost of a generator as well as the rate of outage of the generator must be forecast over the life of the asset.

The COCI stated that this variable cost risk is balanced by the indexing of costs within the PPA. Indexing to fuel costs or to general price indices reduces the likelihood of substantial deviations of costs from forecast values. In addition, the COCI commented that if mechanisms are developed that share this risk with the PPA purchaser, the risk impact on the generation owner will be reduced even more.

The COCI submitted that there are no new sources of long run risk that will develop for which shareholders of the utilities will need to be compensated in 1999/2000 via a higher allowed ROE or a higher equity ratio. The COCI stated that in assessing the long run risks that shareholders face in the current environment as a result of the new regulation, one must recognize that the compensation paid to generation assets within the PPAs will incorporate a fair rate of return on investment. As a result, the long run risk that the shareholders face today is not the increased uncertainty in costs versus compensation, but instead the risk that the rate of return incorporated in the PPA will not fully compensate shareholders for the risks involved in the PPA. Thus, the current owners of generation assets are experiencing changes in terms of long-term risk as a result of the switch from rate of return regulation to the EU Act. They face the change in the risk that future allowed returns will not fully compensate for the risks shareholders face in the future.

In the COCI's view, the shareholders' risk of being under-compensated for future risks has not increased as a result of the change in regulatory environment. The change to the EU Act represents a shift in the form of regulation from a system in which the compensation to shareholders is determined in a quasi-judicial and adversarial proceeding to an administrative system in which the compensation is part of a contract (a PPA). The PPA is determined via assessment by the IAT with specific industry expertise. The Act specifies that the IAT will accept submissions from and consult with interested parties. As a result, the COCI concluded the probability that the utility shareholders will be under-compensated for the risks that they bear will not increase with the change in regulatory regime. The most fundamental business risk issue arising from the EU Act – whether shareholders will continue to be fairly compensated for the risks that they face in the future – has been dealt with in ways that do not act to the detriment of shareholders.

The COCI submitted that there are five aspects of the EU Act that provide protection against risk of the return to generation assets. These are outlined as follows:

- The PPA Balancing Pool mechanism will insulate generation assets from exposure to future competition. To the extent that generators do not bear the full cost of outages in the final PPA design, the PPA balancing pool mechanism will protect generation assets from exposure to future competition. In addition, it is likely that generators will be paid on the basis of availability rather than output.

  The COCI also submitted that it is important to note that even if the generator owner is left exposed to some risk over the extent of outages, the exposure to power pool price variation represents a "second-order" effect. Thus, whatever the final form of the PPA, the exposure of generator owners to power pool price variation will be very small.

- An advantage to entrants over incumbent generation asset owners in a new competitive electricity industry is unlikely. Incumbent regulated firms have off-balance sheet assets such as a working knowledge of the industry, the regulation as well as the match of technology with the market. As a result, incumbents represent the most likely investors in new unregulated generators. These off-balance sheet assets represent a stranded benefit and another offset to any risk that utility shareholders will be less than fairly compensated for investment in existing generation assets under the new system.

- The amended EU Act will remove from generation assets an important liability after 2000: the obligation to serve. This obligation will be removed in the sense that generators will no longer be required to invest in new generation capacity. Under rate of return regulation, a vertically integrated electric utility was obligated to invest in new generating capacity to provide electricity to ratepayers at reasonable prices. In contrast, under the EU Act, these risks have disappeared for generators since the obligation to serve has for the future been replaced by a market mechanism. Rising pool prices are expected to stimulate the entry of new generation assets, similar to price responses promoting new entry in a competitive, unregulated market.

- An additional source of risk reduction in the generation sector is the indemnification by the PPA purchaser of *force majeure* risks and environmental liability risk, representing a risk that would otherwise be incurred by the generation asset owner. Although *force majeure* risks were not borne by the regulated asset owners under rate of return regulation, the scope for expansion of the legal definition of *force majeure* allows for further reduction of this risk in the new environment.

- A final source of risk reduction in the generation sector is a significant reduction in operating leverage. Currently under the EU Act, reservation price transfers from distributors cover the fixed costs of generators. This reduces the operating leverage in the GENCO by decreasing the next fixed operating costs of generation. After 2000, the

entire embedded costs of generators will be paid for by the PPA purchasers, again continuing to transfer risk away from generators.

In summary, the COCI argued that the return on generating assets is protected against uncertainties in demand and insulated from the risk of future competition. While cost forecast uncertainties may have increased for generators, the transfer of operating leverage out of the generating sector has reduced the risks imposed on equity holders from such uncertainties.

The COCI was critical of TransAlta's evidence on business risk presented in Exhibit 133, which was filed by Mr. D. Way in response to a request from the Chairman. The COCI noted that the table in the exhibit summarizing risk assessment is filled with plus signs, indicating TransAlta's view that risk is increasing. However, the COCI submitted that no real conclusion or quantification can be extracted from the table. Also, to the extent that TransAlta's table attempted to demonstrate that risk has increased due to the 1998 amendments to the EU Act, then the COCI would submit that it disagrees with this conclusion.

The COCI noted that Exhibit 133 suggested that GENCO risk has increased with exposure to pool price variation, which in essence captures the impact of future competition in generation. Under the 1996 legislation, the generator faces pool price risk for amounts that differ from the forecast output. As a result, the generator is insured against pool price up to the Unit Obligation Amount (UOA), but beyond that point the insurance is incomplete.

The COCI stated that there remains the exposure for generators that fail to meet their UOAs, or target outputs under the PPAs. However, it is the COCI's understanding that electric industry experience with meeting UOAs has been very strong. In general, the incentives provided in the system should provide for greater reliability and output relative to forecast in the future.

The COCI argued that the exposure to pool price is relatively small since the sensitivity to pool price represents a "second-order" effect. The COCI further commented that the entire impact of competition on existing generators is through the pool price. Existing generators have to meet the cost standard imposed by their forecast variable costs, but they do not have to meet the efficiency standards of new competitive entrants. Consequently, it is only through the pool price that a new technology would have any impact. Thus, the COCI concluded that pool price fluctuations are irrelevant except during the time when output is likely to be less than UOA.

The COCI also submitted that the exposure of existing regulated generators to new competition is very small. The Alberta electricity market is different from other regulated markets where the incumbents simply must meet the market test, facing new competition. Instead, the COCI stated that the EU Act structure is a hybrid of competition and regulation. Competition and the price system are allowed to operate. At the same time, a regulatory contract is in place to cover the costs of generation assets that were invested at the time of regulation. As a result, a central feature of the EU Act is that competition can operate to the benefit of ratepayers at the same time that incumbent generators are insured against the vagaries of the market.

The COCI concluded that TransAlta's Exhibit 133 does not provide sufficient evidence that business risk has increased at all. In addition, Exhibit 133 does not provide support for an increase in TransAlta's 40% common equity component that the Board found to be appropriate in Decision U97065.

The COCI argued that EPGI's evidence and argument relating to the 1996 CCES report should be ignored. This report relates to a wholly different entity, in a different location, and a different time. Neither Dr. Waters nor Dr. Winter provided any evidence in this proceeding relating to the capital structure of EPGI. In addition, the observations cited by Edmonton Power are matters of speculation on the part of Dr. Evans. Also, EPGI did not cross-examine Dr. Waters on the CCES report, although it had the opportunity to do so. A fundamental principle that has existed historically is that a party who seeks to impugn the testimony of a witness has a duty to cross-examine the witness on that testimony.

Position of IPCAA

IPCAA presented its views of GENCO risk in its evidence. IPCAA submitted that GENCOs receive the majority of their revenue from the fixed Reservation Prices charged to the Power Pool. However, a portion of the GENCO's revenue results from the surplus/shortfall component, which can be subject to variation. IPCAA also noted that GENCOs have a greater proportion of their cost of service in variable operating costs, in comparison to TRANSCO's share of variable costs.

With respect to revenue risk, IPCAA stated that the GENCO's revenue risk results from the fact that the actual surplus/shortfall will be different than forecast, due to changes in the Pool Price and/or changes in the amount of total generation. IPCAA submitted that these risks potentially can be controlled by the use of deferral accounts.

Position of IPPSA/SPPA

IPPSA/SPPA was concerned that Dr. Kolbe did not consider the concentration of the generation market nor the potential for the exercise of market power in Alberta when he presented his evidence.[333] IPPSA/SPPA argued that the dominance that TransAlta holds in the Alberta Generation market must be considered when setting the appropriate level of capital structure and rate of return. IPPSA/SPPA confirmed that when this issue is incorporated into the evidence, there is no justification for an increased "risk" premium. IPPSA/SPPA further speculated that had Dr. Kolbe factored these issues into his argument, he most likely would have determined that the market is not nearly as competitive as he would have thought, consistent with the Brattle Groups findings in the U.K.[334]

333 T. 4992/18 –22; T. 4998/7 13
334 T. 4988/13 – 4989/15

Position of ENMAX

ENMAX responded to EPGI's statement that its bond rating was based on the assumption that the Board would accept the forecast actual capital structure contained in EPGI's application. In support of this statement, EPGI relied on the evidence of Ms. McLeod. However, ENMAX argued that Ms. McLeod's statements are at odds with the information provided by EPGI in response to ENMAX.EPGI-25. Specifically, no such statement appeared in the letter of 15 February 1999 from CBRS with respect to EPGI. As a result, ENMAX concluded that the Board should rely on the statements made by the bond rating agencies as found in ENMAX.EPGI-25, rather than refer to the interpretation of those reports by EPGI's witness.

Position of LE/RD

LE/RD noted that a considerable amount of the EPGI's argument in Section 6.2 related to business risks incurring as a result of the uncertainty arising from the PPA regime. In particular, in Section 6.2.2, at pages 6-4 to 6-5, EPGI quoted Ms. McLeod's evidence that EPGI is exposed to greater business risk than previously existed "due to the twenty year term of the agreements, during which no regulatory review or negotiation of contract terms is contemplated." In reply argument, LE/RD responded that the PPA filings of the Utilities, including EPGI, indicate a significant qualifier with respect to Ms. McLeod's statement. In particular, LE/RD argued that there are a potential number of adjusters and re-openers which have been designed to protect the Utilities from the risk that Ms. McLeod has identified. LE/RD also noted that the disconnect between the 1999/2000 rate hearings and the PPA process has generated other similar difficulties. These issues have resulted in increased costs being requested by the Utilities for the 1999/2000 period as well as higher returns as a result of alleged risks in the PPA process.

Board Findings

The Board notes that Dr. Kolbe's original evidence suggested that the GENCO function was less risky than the integrated utility by approximately 200 basis points (2%) in terms of a differential on common equity. TransAlta, in argument referred to that position as reflective of the longer-term risks. TransAlta argued that when the extremely tight market in the near term was considered the risk of the GENCO function was equal to the integrated utility risk, resulting in a GENCO common equity ratio differential of 0 basis points (0%).

Using the mid-point of the COCI recommendations, the Board notes that TRANSCO's risk would be 75% of GENCO's risk (based on an assessment of 60-90% of GENCO risk) whereas DISCO's risk would be 25% more risky than GENCO (based on an estimate of 110-140% of GENCO risk). If these relative risk factors are used with TransAlta's weighting of rate base in each function, the risk of the GENCO would be close to being equivalent to the integrated utility risk, implying a GENCO common equity ratio differential of 0 basis points (0%).

The Board notes that EPGI submitted that the GENCO function was some 1100 basis points (11%) higher than the TRANSCO function in terms of a common equity differential. The Board also notes that EPGI did not present any evidence respecting the relative risk of the GENCO

function to the integrated utility. However, the Board notes that given the very high proportion of Generation rate base relative to the combined entity of EPGI/EPTI/EPDI (i.e., 81% of 1999 Rate Base with estimated Distribution as shown on p.2 of Mr. Marcus' evidence), it is likely that the risk differential between GENCO and the integrated utility in the case of EPGI would be very slight, resulting in a GENCO common equity ratio differential of close to 0 basis points (0%).

The Board also notes that a number of participants presented the view that long-term post-2000 business risks need to be acknowledged in order to properly analyze GENCO risks in the current proceeding. For example, Drs. Waters and Winter representing the COCI argued that it is appropriate to focus on long-term risks because equity investors have long-run investment horizons. In addition, Ms. McLeod representing EPGI stated that for Generation companies, the future operating environment will be fundamentally altered by the PPAs.

At the same time, the Board notes that there was not universal agreement that long-term risks need to be incorporated into the business risk analysis of Generation. For example, TransAlta concluded that the allowed cost of capital should reflect the risks of the period corresponding to the period the rates are to be in effect. Otherwise, shareholders could be over or under compensated based on risks for a subsequent period.

To the extent that the Board accepts the argument or notion that long-term risks should be incorporated into the analysis of business risk, the Board observes that there does not appear to be a consensus in terms of the perceived impact of long-term risks and the PPA regime on GENCO risk. In addition, there are various protective devices in the PPA structure and in the post-2000 period that will effectively reduce the potential business risk of Generation assets. For example, the Board notes that the COCI addressed some of the protective aspects of the EU Act that will provide protection against risk of the return to Generation assets.

Furthermore, as summarized by the FIRM Customers, the longer-term risks are being taken into account by the IAT proceeding currently in progress. The purpose of the IAT proceeding is to determine the long-term post-2000 business risks of existing GENCO assets.

The Board accepts the view that during the 1999-2000 period, Generation risks have been mitigated by the transfer of risk from Generation to Distribution caused by the legislative hedges. With respect to the longer-term, the Board agrees with the FIRM Customers' argument that GENCO risks will be slightly greater than current risks, primarily as a result of indexing of costs and performance to benchmarks for up to 20 years. Based on their long-run investment horizons, equity investors will be factoring these potentially higher long-term risks into their investment decisions. However, the Board believes that less weight should be placed on the longer-term perspective since a central goal of the current IAT proceeding is to establish a rate of return that incorporates the long-term business risk of GENCO assets in the post-2000 period. For all of the above reasons, based on short and long-term considerations, the Board generally concludes that the business risk of the GENCO is approximately in line with the risk of the integrated utility.

In order to mitigate some of the GENCO risk, the Board notes that some of the consumer groups advocated the establishment of deferral accounts to respond to and reduce the impact of pool price and other related risks. The Board has accepted the argument for deferral accounts elsewhere in this Decision and as a result has approved the implementation of a deferral account to deal with the uncertainty of pool prices.[335] The Board believes that with the advent of GENCO pool price deferral accounts, GENCO business risk will be mitigated somewhat.

Incorporating the impact of a deferral account with the Board's general conclusions about GENCO risk, the Board concludes that the final overall risk of the GENCO is slightly less than the risk of the integrated utility. As a result, in terms of a common equity ratio, the Board would assign to the GENCO a common equity ratio differential in the order of 100 basis points (1%) lower than the common equity ratio of the integrated utility.

Thus, based on the Board's assessment of business risk of the GENCO for 1999 and 2000, the Board has determined that an acceptable range of common equity ratios for an investor-owned GENCO is in the range of 39-41%. This target range provides a mid-point of 40%, reflecting the slightly lower risk of the GENCO relative to the integrated utility. The Board notes that given an allowed common equity ratio of 39-41% (i.e., a mid-point of 40%) and an equity rate of return of 9.00-9.50% (determined in the Return on Equity section), TransAlta GENCO's before tax interest coverage will be 3.11-3.20 times for 1999 and 3.24-3.34 times for the year 2000. On an after-tax basis, TransAlta-GENCO's interest coverage will be 2.06-2.11 times for 1999 and 2.10-2.15 times for the year 2000.

Taking into consideration all of the above, the Board considers that the following capital structure (i.e., investor supplied funds; excluding no-cost capital and contributions) for TransAlta-GENCO will reflect the business and financial risks that are faced by the Utility during the 1999-2000 period:

TransAlta-GENCO Capital Structure

Board Approved

	Common Equity	Preferred Equity	Total Equity	Debt
TransAlta-GENCO 1999-2000	39.0-41.0%	9.5%	48.5-50.5%	49.5-51.5%
Mid-point	40.0%	9.5%	49.5%	50.5%

[335] See Board Findings in GENCO Deferral Accounts Section 3(a)(4)

Accordingly, the Board considers that a common equity ratio of 39-41% is appropriate for TransAlta-GENCO for the test years 1999 and 2000.

With regard to a determination of EPGI's capital structure, the Board notes that EPGI's financial risks are considerably higher than the financial risks of TransAlta GENCO. In particular, the Board notes the evidence of Ms. McLeod on behalf of EPGI/EPTI wherein she stated the following:

> The shareholders of EPTI and EPGI are exposed to greater financial risk than the shareholders of either TransAlta Utilities Corporation ("TransAlta") or Alberta Power Limited ("APL"). This incremental financial risk exposure relates to two factors. First, both TransAlta and APL have a substantial preferred share component to their capital structures which has the effect of reducing the proportion of senior debt and increasing interest coverage ratios. In addition, EPTI and EPGI are not currently taxable, with the result that their stand-alone corporate debt interest coverage ratios are relatively very low at the applied-for capital structures and rates of return on common equity.
>
> As a result, EPGI expects to receive a debt rating in the BBB category from CBRS, which falls below the effective minimum standard of financial integrity for Canadian corporate issuers and which is substantially lower than the bond ratings of TransAlta and Canadian Utilities Limited.
>
> I believe it would be impractical at this time to attempt to compensate for these incremental financial risk factors by making a further adjustment to my recommendation with respect to the appropriate common equity ratio for the two companies. However, these factors would tend to lend emphasis to the upper end of the reasonable range for EPGI.[336]

The Board notes that in the current proceeding some of the parties, including EPGI and EPTI, have utilized the two bond ratings of "B++" and "BBB" on an interchangeable basis. A "B++" bond rating represents a CBRS rating, whereas a "BBB" bond rating represents a DBRS rating. In this regard, the Board is aware that the CBRS bond rating agency has recently assigned a B++ rating to EPGI with regard to its senior debt securities. However, the Board notes that no evidence has been presented by EPGI in the present proceeding that EPGI has been given a "BBB" bond rating by DBRS, or that the DBRS bond rating agency has established a bond rating for EPGI's debt obligations. Thus, while it possible to discuss the impact of a "B++" rating or a "BBB" rating on a company's ability to raise capital, it is uncertain what relevance a "BBB" rating has with regard to the financial circumstances of EPGI. In the Board's view, any discussion of EPGI's ability to raise capital is solely related to CBRS's B++ rating with respect to the utility's debt obligations.

[336] ENMAX.EPGI-22(d)

In response to EPGI's higher financial risk, the Board observes that Dr. Evans argued that a higher common equity ratio was required "when an income tax 'cushion' is unavailable to support the payment of bond interest."[337] Of particular interest, the Board notes Dr. Evans' confirmation that the common equity ratio could be lowered by 2.5% (or 250 basis points) in absolute terms whenever EPGI commences to pay income taxes (confirming a 47.5% common equity ratio that could be used instead of an original recommended upper ratio of 50%). In addition, the Board observes that EPGI's embedded cost of debt is considerably higher than the cost of debt for TransAlta GENCO, which also contributes to a lower coverage ratio for EPGI.

Taking all of the above into consideration, the Board considers that it is appropriate to allow EPGI, for the test years, a higher common equity ratio in comparison to the common equity ration of TransAlta GENCO. In recognition of the higher financial risks for EPGI, the Board considers that a positive differential of 400 basis points relative to TransAlta GENCO would be appropriate during the test period.

Thus, based on the Board's assessment of business risk of the GENCO and the particular financial risks of EPGI (with its current ownership and tax structure) for 1999 and 2000, the Board has determined that an acceptable range of common equity ratios for EPGI is in the range of 43-45%, providing a mid-point of 44%. This Board decision in effect allows EPGI a common equity ratio just below the requested range of 46.0-48.8% for 1999-2000 period.

The Board notes that given an allowed common equity ratio of 43-45% and an equity rate of return of 9.00-9.50% (determined in the Return on Equity section), EPGI's interest coverage on a before and after tax basis will be 1.70-1.73 times for 1999 and 1.70-1.74 times for the year 2000. This interest coverage ratio should be compared to the after-tax coverage ratio of an investor-owned utility. In this regard, EPGI's interest coverage is below TransAlta GENCO's after-tax interest coverage (which is above 2.0 times). However, the Board notes that as a result of EPGI's particular financial circumstances (i.e., high embedded cost of debt), EPGI would require a significantly higher common equity ratio than the range of ratios requested for the test period in order realize an interest coverage of 2.0 times, based on an approved equity rate of return of 9.00-9.50%. In addition, based on COCI's argument that TransAlta's interest coverage ratio should improve as the Utility refinances its debt at lower interest rates, the Board considers that COCI's argument could be applicable to EPGI. As a result, it is possible that EPGI's interest coverage ratio will also improve as the Utility refinances its debt. In this regard, the Board anticipates that as the opportunity arises, EPGI will be in a position to refinance its debt at interest rates that are lower relative to its embedded cost of debt. Thus, EPGI's interest coverage ratios could potentially improve, rising to higher levels over time.

[337] Dr. Evans evidence p.52

Accordingly, the Board considers that its determinations will allow EPGI to maintain its current credit rating. In addition, the Board's determinations will allow EPGI to attract capital for new construction and refinancing purposes on favourable terms.

In summary, the Board considers that the following capital structure (i.e., investor supplied funds, excluding no-cost capital and contributions) for EPGI will reflect the business and financial risks that are faced by the Utility during the 1999-2000 period:

EPGI Capital Structure

Board Approved

	Common Equity	Preferred Equity	Total Equity	Debt
EPGI 1999-2000	43.0-45.0%	0.0%	43.0-45.0%	55.0-57.0%
Mid-point	44.0%	0.0%	44.0%	56.0%

Accordingly, the Board considers that a common equity ratio of 43-45% is appropriate for EPGI for the test years 1999 and 2000.

(4) TRANSCO Risk and Capital Structure

Position of the Intervenors

Position of the FIRM Customers

The FIRM Customers submitted that all parties agreed that the Transmission function is significantly less risky than the average cost of the entire Utility function.[338] The major reason for the reduced risk is the requirement for Transmission wire owners to receive their payments on a fixed cost basis without any demand risk.[339] Another reason for the lower risk is the consideration that the existing transmission system is largely a natural monopoly with a stable cost structure.

The FIRM Customers argued that Dr. Kolbe's testimony on behalf of TransAlta misstates the reason for the reduced risk of the Transmission function. Dr. Kolbe claimed that risk is reduced because of the balancing account between the TA and the DISCO, which protects the TA from revenue loss but has no impact on the transmission owner.[340] The FIRM Customers stated that this assumption is incorrect since he is confusing this deferral account with the fixed cost rate

[338] Exhibit 159, p.4, Table 2
[339] Exhibit 162, p.39
[340] Exhibit 13, Dr. Kolbe

design between the TA and the transmission facility owner, which represents the method of protecting the transmission owner from demand risk.

In reviewing Dr. Kolbe's evidence, the FIRM Customers stated that it appears his analysis is flawed with respect to the issue of Transmission versus Distribution function risk. For example, Dr. Kolbe suggested that Distribution risk is higher because of "opportunities for bypass" and "competitive pressure on margins."[341] However, the FIRM Customers argued that Dr. Kolbe's reasoning does not reflect the reality of the Alberta market. The FIRM Customers noted that the transmission system has been subject to industrial bypass since 1996 with the implementation of DRD legislation concerning industrial systems designations. In contrast, the Distribution wires function remains subject to franchise area protection and is subject to little, if any, bypass competition.

With respect to competitive pressures on margins, the FIRM Customers submitted that the new DRD Transmission Planning Guidelines allow the TA to solicit competitive procurement of new transmission facilities, subject to certain thresholds.[342] Since these Guidelines authorize the competitive construction of transmission facilities in a Utility's franchise area, it would follow that the procurement practices will tend to exert competitive pressures on margins. The FIRM Customers contrasted this transmission competition with the Distribution wires function in which construction and ownership remains in a monopoly setting within the franchise area of the distributor.

The FIRM Customers concluded that in terms of wires components, the Transmission wires function may actually be exposed to slightly more competitive risks than the Distribution wires function, although it is less risky with respect to demand and rate design.

The FIRM Customers did not support the proposed capital structure requested by EPGI and EPTI.[343] However, the FIRM Customers did not believe the proposed capital structure would have a material effect on the costs and rates for either EPGI or EPTI in the 1999-2000 period. Unlike TransAlta, the costs of debt and equity are similar for both functions. In addition, the FIRM Customers also noted that neither EPGI nor EPTI will be paying income taxes during this two-year time frame. Therefore, the FIRM Customers submitted that the Board could adopt EPGI/EPTI's requested capital structure with the proviso it would not consider that such a ruling sets a precedent for future proceedings.

Position of COCI

The COCI presented its assessment of the risks in the return on investment in Transmission assets under the EU Act. According to Drs. Waters and Winter, risks related to the Transmission function are minimal, for the following reasons:

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[341] Exhibit 13, p.47
[342] Exhibit 180
[343] Exhibit 159, p.20

- There are no volume-related revenues or costs in the income statement of a transmission company under the new system. Revenue is in the form of a known lease payment from the TA.
- Costs are highly predictable in the transmission sector.
- Transmission assets remain a natural monopoly. In the short term, they will continue to be regulated under rate of return regulation.
- There is a high probability that the allowed rate of return to Transmission assets will be indexed to long-term interest rates, as is the case for other regulated utilities in Canada. The linkage will effectively reduce the low uncertainty in the determination of the allowed return to Transmission assets.
- The TA bears the uncertainties related to the costs of system support services and line losses. While the costs are passed on to some extent to distributors and then to ratepayers, the TFOs bear none of these costs.

In summary, Drs. Waters and Winter concluded that transmission assets have little risk in comparison to the overall average risk of a vertically integrated electric Alberta utility, which represents a high-grade utility.

In terms of an assessment of the business risks of the transmission function relative to the business risks of generation, Drs. Waters and Winter expressed the view that transmission risks are less than 90% of the risks of generation assets, due to the risk protection factors outlined above. As a lower bound, transmission risks are more than 60% as risky as generation in light of the risk protection factors in place for generation. Drs. Waters and Winter further commented that the specifics of the final PPA design will ultimately determine the level of the relative risk factor within the range of 60 to 90%.

The COCI argued that Edmonton Power's evidence and argument relating to the 1996 CCES report should be ignored. This report relates to a wholly different entity, in a different location, and a different time. Neither Dr. Waters nor Dr. Winter provided any evidence in this proceeding relating to the capital structure of Edmonton Power. In addition, the observations cited by Edmonton Power are matters of speculation on the part of Dr. Evans. Also, Edmonton Power did not cross-examine Dr. Waters on the CCES report, although it had the opportunity to do so. A fundamental principle that has existed historically is that a party who seeks to impugn the testimony of a witness has a duty to cross-examine the witness on that testimony.

Position of IPCAA

IPCAA submitted that the TRANSCO is the least risky function. In support of this statement, IPCAA noted that there is no revenue variation since the TRANSCO's costs are recovered by a guaranteed annual payment from the TA. In addition, while the actual costs may vary from projected costs, the majority of the TRANSCO's costs are comprised of return, income taxes and depreciation. For example, TransAlta-TRANSCO capital-related costs represent 77% of proposed total 1999 costs, whereas for EPTI capital-related costs represent 67% of 1999 costs.

In addition, IPCAA submitted that risks are low due to the fact that TRANSCOs are not obligated to build facilities for new customers. Instead, the TA is in the position of procuring such additions on a competitive basis.

Position of TransAlta

Dr. Kolbe provided evidence for TransAlta on the differential risk by function. Based on the evidence, he concluded that Transmission was the least risky function of the three functions. As a result, Dr. Kolbe recommended an ATWACC of 6½% for Transmission, which is ½ percentage points lower than the bundled utility value of 7% estimated by Dr. Vilbert. In addition, the new flow-through account for transmission shifts risk from the utility to customers. Given the risk reduction related to the flow-through account available to the TA, Dr. Kolbe recommended that the ATWACC for Transmission should be adjusted and further reduced by ¼ percentage point, to 6¼%. This ATWACC percentage translates into a common equity ratio of 33.15% for TRANSCO, assuming an integrated utility common equity percentage of 42% and a constant cost of equity across the lines of business.[344]

TransAlta noted that the FIRM Customers agreed with its view that the Transmission function of an integrated utility is materially less risky than the integrated utility itself. However, the FIRM Customers disputed Dr. Kolbe's analysis of the relative risk of Transmission and the "wires" part of Distribution. TransAlta responded that Dr. Kolbe did not prepare a separate analysis of the various parts of the Distribution function, since no breakdown of the DISCO was called for by the Board.

TransAlta also noted that the FIRM Customers claimed that the transmission system has been subject to industrial bypass since 1996. In response to this statement, TransAlta submitted that the effect of the industrial system policy is to permit customers within an industrial system to save on the postage stamp transmission tariff if the actual transmission costs at the site are less than the postage stamp rate. However, the policy does not give industrial customers the right to build a competing transmission system or to sell transmission access in other parts of the Province to other customers, common mechanisms often associated with the term "bypass." In addition, it does not permit industrial customers to avoid the service of the transmission grid, since the physical system is unaffected. Thus, TransAlta claimed that the industrial system policy has permitted a lowering of transmission rates in a few selected areas and in general its impact has been very minor.

TransAlta mentioned that despite the FIRM Customers' claim that Transmission "wires" must be riskier than Distribution "wires" as a result of the possibility of industrial customer bypass, the FIRM Customers concluded that Distribution wires may require a slightly higher return than Transmission. Thus, despite its concerns about Dr. Kolbe's analysis of the relative risk of

[344] Table No. ALK-2 Revised Panel A:1999

Transmission versus Distribution, the FIRM Customers did not disagree with his conclusions regarding the "wires" parts of the two lines of business.

Position of EPTI

EPTI requested that Dr. Evans develop a range of capital structure values consistent with its long-term business risks. EPTI also requested that Ms. McLeod evaluate the appropriate capital structure ratios from a capital markets perspective.

EPTI submitted that its forecast actual capital structures are consistent with Dr. Evans' recommendations. The forecast 1999 and 2000 actual capital structures of EPTI are:[345]

	1999	2000
Debt	64.7%	65.9%
Common Equity	35.3%	34.1%

EPTI has requested approval of these forecast actual capital structures for the purpose of weighting the costs of debt and common equity to arrive at a fair rate of return. The reasons for using forecast actual capital structures rather than deemed capital structures have been discussed in the Position of EPGI section. EPTI submitted that the essence of the question before the Board is whether the business risks of EPTI are sufficient to justify its forecast actual common equity ratios.

EPTI submitted that there was essentially unanimous agreement among the experts that Transmission is the least risky function of the Utilities.[346] EPTI noted Mr. Drazen's comment that "everyone agrees that the TRANSCO function (viz., Transmission Facilities Owner) has the least risk, the GENCO is then higher."[347]

Based on his assessment of business risk, Dr. Evans concluded:

- The 1999/2000 business risks of EPTI are greater than the TRANSCO business risks of Edmonton Power in 1996 largely due to the absence of diversification benefits.[348]
- If the absence of diversification benefits in 1999/2000 is ignored, then EPTI's 1999/2000 business risks are not materially different from those that existed for Edmonton Power TRANSCO in 1996.[349]

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[345] Exhibit 3, p.11

[346] Exhibit 4, p.46; ENMAX.EPGI-22(d), p.4; Exhibit 162, p.3; Exhibit 158, p.4; Tr. p.5206; Exhibit 13, Volume 2, Appendix 4, p.47, 50-51

[347] Exhibit 136, Volume 1, Section 2, p.5

[348] Exhibit 4, p.42-43

[349] Exhibit 4, p.42-43

- The business risks of EPTI are somewhat greater than the business risks of gas pipelines and somewhat less than the business risks of gas distributors.[350]

EPTI stated that despite the agreement about Transmission risks among all of the experts, Ms. McLeod and Dr. Evans were the only witnesses who incorporated these general comments respecting relative business risk into capital structure recommendations for EPTI.

In his analysis of other energy utilities and pipelines, Dr. Evans noted that the midpoint of the range of common equity ratios for gas distributors is 37.5%, and the midpoint of the range of common equity ratios for gas pipelines is 32.5%.[351] As a result, Dr. Evans concluded that the range of reasonable common equity ratios for EPTI is 32.5-37.5%, with the focus at the upper end of the range until EPTI commences to pay income taxes.[352]

In her assessment of Transmission business risk, Ms. McLeod concluded:

> In my opinion, the business risks of the transmission function within the Alberta electric industry are comparable to those of the major Canadian natural gas transmission, gathering and distribution companies. Consequently, I believe that a capital structure including approximately a 35.0% common equity is appropriate for EPTI.[353]

EPTI stated that it believed that no intervenor took issue with the reasonableness of its forecast actual capital structure ratios.

Similar to EPGI, EPTI discussed the 1996 report prepared by Dr. Waters regarding the appropriate capital structure and fair rate of return for the transmission operations of CCES Report. The CCES Report was filed in response to an information request in the current proceeding.[354] EPTI drew several observations and conclusions from the CCES Report.

First, similar to EPTI's status, Dr. Waters noted that the absence of preferred share capital and the status of CCES as a non-taxable entity caused the financial circumstances of CCES to differ from that of investor-owned, taxable Utilities.[355] Second, based on Dr. Waters' recommended deemed capital structure for the Transmission function for CCES (47.5% common equity, 39.2% debt and 13.3% contributions in aid of construction), EPTI speculated that had Drs. Waters undertaken a similar study in the current proceeding, he may well have concluded that the forecast actual common equity ratios for EPTI were insufficient in light of EPTI's business risks.

[350] Exhibit 4, p.45
[351] Exhibit 4, p.54
[352] Exhibit 4, p.54
[353] ENMAX.EPGI-22(d), p.4
[354] EPGI/EPTI.ENMAX-8
[355] EPGI/EPTI.ENMAX-8, CCES Report, p.1-2

Third, EPTI noted that Dr. Waters concluded that a 47.5% common equity ratio for the CCES Transmission business was required in order to maintain a reasonable balance in respect of the coverage ratios of AE and TransAlta, after incorporating the impact of Calgary's non-taxable status on its pre-tax interest coverage.[356] Depending on the common equity rate of return, the CCES Transmission coverage ratio at a 47.5% common equity ratio was in the range of 2.3-2.5x.[357]

EPTI stated that the coverage ratio resulting from its requested 11.0% common equity rate of return and forecast actual capital structures is 1.6x.[358] However, EPTI noted that if an 8.25% rate of return on common equity were adopted by the Board, consistent with the recommendations of Drs. Waters and Winter, then EPTI's interest coverage ratios would be 1.4-1.5x.[359] All of these interest coverage values are substantially below the 1.9-2.1x coverage values rejected as insufficient by Dr. Waters for the CCES Transmission business in 1996.

EPTI argued that Dr. Waters might similarly have rejected a 40.0% common equity ratio as too low for EPTI in this proceeding had he conducted a study similar to that set out in the CCES Report. At the very least, EPTI was of the view that Dr. Waters would not have concluded that EPTI's applied-for common equity ratios were unnecessarily high.

In summary, EPTI submitted that based on the evidence, its forecast actual capital structure ratios are reasonable. Therefore, EPTI concluded that the Board should accept the applied-for capital structure ratios as reasonable for the purpose of determining EPTI's 1999 and 2000 return requirements.

Board Findings

The Board notes that there was unanimous agreement amongst the parties that Transmission risk is relatively low and is the least risky function of the electric utilities. The Board also notes that the parties presented relatively similar reasons for the low risk. TRANSCO risk is low for several major reasons, including the consideration that revenue for the Transmission company is in the form of a known tariff payment from the TA, the TRANSCO has a stable cost structure which is highly predictable and Transmission assets remain a natural monopoly.

The Board agrees with the position that the risk of the Transmission function is relatively low and materially lower than the risk of the integrated utility. As a result, the capital structure for the TRANSCO should be significantly adjusted to reflect the relatively low level of risk that is characteristic of the Transmission function.

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[356] EPGI/EPTI.ENMAX-8, CCES Report, p.8-9
[357] EPGI/EPTI.ENMAX-8, CCES Report, Table 2B, p.7
[358] Exhibit 39, p.5
[359] Exhibit 39, p.5

Thus, in terms of a common equity ratio, the Board is of the view that the TRANSCO common equity ratio should be in the order of 600 basis points (6%) lower than the integrated utility common equity ratio.

Accordingly, based on the Board's assessment of business risk of the TRANSCO for 1999 and 2000, the Board has determined that an acceptable range of common equity ratios for an investor-owned TRANSCO is in the range of 34-36%. This target range provides a mid-point of 35%, reflecting the significantly lower risk of the TRANSCO relative to the integrated utility. The Board notes that given an allowed common equity ratio of 34-36% and an equity rate of return of 9.00-9.50% (determined in the Return on Equity section), TransAlta-TRANSCO's before tax interest coverage will be 2.79-2.87 times for 1999 and 2.88-2.96 times for the year 2000. On an after-tax basis, TransAlta-TRANSCO's interest coverage will be 1.87-1.91 times for 1999 and 1.90-1.94 times for the year 2000.

Taking all of the above into consideration, the Board considers that the following capital structure (i.e., investor supplied funds, excluding no-cost capital and contributions) for TransAlta-TRANSCO will reflect the business and financial risks that are faced by the Utility during the 1999-2000 period:

TransAlta-TRANSCO Capital Structure

Board Approved

	Common Equity	Preferred Equity	Total Equity	Debt
TransAlta-TRANSCO 1999-2000	34.0-36.0%	9.5%	43.5-45.5%	54.5-56.5%
Mid-point	35.0%	9.5%	44.5%	55.5%

Accordingly, the Board considers that a common equity ratio of 34-36% is appropriate for TransAlta-TRANSCO for the test years 1999 and 2000.

With regard to a determination of EPTI's capital structure, the Board notes that EPGI/EPTI requested a differential of 1100-1500 basis points (11-15%) in the common equity ratio for the two entities. Specifically, EPGI requested a common equity ratio of 46%-49% for 1999-2000, whereas EPTI's requested ratio was 34%-35%. If the Board were to maintain the requested 1100-1500 basis point negative differential relative to the Board's findings respecting EPGI, this would result in a recommended common equity ratio of 29%-33% for EPTI (i.e., EPGI's common equity ratio of 44% minus 11%-15%). However, the Board notes the evidence of Ms. McLeod on behalf of EPTI wherein she stated the following:

> In my opinion, the business risks of the transmission function within the Alberta electric industry are comparable to those of the major Canadian natural gas transmission, gathering and distribution companies. Consequently, I believe that a capital structure including approximately a 35.0% common equity is appropriate for EPTI. The forecast actual common equity ratio of EPTI of 35.2% for 1999 and 34.1% for 2000 is consistent with this recommendation.[360]

In addition, the Board notes the evidence of Ms. McLeod that "because of its size, EPTI will not be seeking a formal debt rating."[361] Similarly, Dr. Evans confirmed in his evidence that EPTI will not have a formal bond rating.[362]

Taking all of the above into consideration, the Board accepts the recommendation of Ms. McLeod, noting that a common equity ratio of 35% for EPTI would be consistent with the Board's award for TransAlta TRANSCO.

Thus, based on the Board's assessment of business risk of the TRANSCO and the evidence on behalf of EPTI, the Board has determined that an acceptable range of common equity ratios for EPTI (with its current ownership and tax structure) is in the range of 34-36%, providing a mid-point of 35%. This Board decision in effect allows EPTI to realize a common equity ratio that is in line with its requested range for the 1999-2000 period.

The Board notes that given an allowed common equity ratio of 34-36% (i.e., midpoint of 35%) and an equity rate of return of 9.00-9.50% (i.e., midpoint of 9.25%)(determined in the Return on Equity section), EPTI's interest coverage on a before and after tax basis will be 1.48-1.51 times for 1999 and 1.52-1.55 times for the year 2000. This interest coverage ratio should be compared to the after-tax coverage ratio of an investor-owned utility. In this regard, EPTI's interest coverage is below TransAlta TRANSCO's after-tax interest coverage (which is slightly below 2.0 times) due to EPTI's higher embedded cost of debt.

Similar to EPGI, the Board considers that it is possible that EPTI's interest coverage ratio will also improve as the utility refinances its debt. In this regard, the Board anticipates that as the opportunity arises, EPTI will be in a position to refinance its debt at interest rates that are lower relative to its embedded cost of debt. Thus, EPTI's interest coverage ratios could potentially improve, rising to higher levels over time.

In summary, the Board considers that the following capital structure (i.e., investor supplied funds; excluding no-cost capital and contributions) for EPTI will reflect the business and financial risks that are faced by the Utility during the 1999-2000 period:

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[360] ENMAX.EPGI-22(d)
[361] ENMAX.EPGI-22(d)
[362] Evidence, p.58

EPTI Capital Structure

Board Approved

	Common Equity	Preferred Equity	Total Equity	Debt
EPTI 1999-2000	34.0-36.0%	0.0%	34.0-36.0%	64.0-66.0%
Mid-point	35.0%	0.0%	35.0%	65.0%

Accordingly, the Board considers that a common equity ratio of 34-36% (i.e., midpoint of 35%) is appropriate for EPTI for the test years 1999 and 2000.

(5) DISCO Risk and Capital Structure

Position of the Intervenors

Position of the FIRM Customers

The FIRM Customers submitted that Distribution risks must be divided into separate components, with wires ownership on the one hand and retailing and brokerage on the other.[363] The FIRM Customers noted that a number of witnesses including Dr. Kolbe failed to make this separation and did not prepare any information allowing such a separation to be made.[364]

The FIRM Customers argued that failure to separate these components will lead to a number of problems, based on the changes in regulatory structure expected to occur in 2001. For example, the Board must ensure that compensation for retailing brokerage risks, which is no longer present after 2001, does not end up in the Distribution wires rates (e.g., through a loose performance-based ratemaking structure). In addition, the Board should assign compensation for brokerage and retail risks to the correct customers in any future Phase II proceedings as well as exclude them from the DAT.[365]

The FIRM Customers submitted that Distribution wires ownership risks are similar to those for transmission. The technology and cost structure is known. Also, Distribution is normally a monopoly in any given area. At the same time, the FIRM Customers argued that Distribution wires may require a slightly higher return than Transmission. There is some demand risk in distribution due to the fact that some Distribution costs are recovered in fixed rates. In addition, Transmission costs are absolutely fixed.[366] Mr. Marcus estimated the required return for

[363] Exhibit 159, p.13-15; Exhibit 136, Volume I, p.1-5, Volume IV, p.1-1 to 1-5
[364] FIRM-TAU-91; FIRM-TAU-99
[365] Exhibit 159, p.3-15
[366] Marcus, Exhibit 159, p.7-8

Distribution wires to be no more than 25 basis points above Transmission.[367] On the other hand, Transmission may be exposed to somewhat more competitive risks than Distribution wires.

The remaining risk relates to retailing and brokerage. In his evidence, Mr. Marcus separated the two functions, recognizing retailing involves the provision of services such as metering and billing as well as marketing. Brokerage, on the other hand, involves risks associated with the acceptance, delivery, and pricing of power. For example, a gas distribution company has both wires and retailing functions, but bears little brokerage risk because of protection through deferral accounts.[368]

The FIRM Customers explained that brokerage risk principally involves the hedging of Generation costs. Thus, risks will evolve whenever DISCOs are required to sell a commodity whose costs fluctuate over time at fixed rates. As a result, Mr. Marcus argued that it would be almost impossible for a utility to manage a completely unhedged pool price without a deferral account.[369] For example, gas utilities have deferral accounts for purchased gas for this purpose. In the current environment, the FIRM Customers confirmed that legislated hedges manage a significant portion of those risks, hedging approximately 85% of the pool price variation on a province-wide basis (varying slightly across Utilities).

In theory, the fixed reservation price could expose the DISCO to demand risks (i.e. spreading fixed costs over fewer kilowatt-hours of sales).[370] However, the FIRM Customers argued that this potential is significantly offset because the pool price and demand are negatively correlated (i.e., higher demand is related to lower pool prices and vice-versa). Thus, if demand declines, fixed costs are spread over fewer kilowatt-hours of sales, but the pool price will also fall significantly on the 15% of power unhedged. Consequently, the FIRM Customers concluded that the relationship between demand and the pool price reduces the risk of demand changes being borne by the DISCO.[371] However, the DISCO must bear other pool price risks due to supply, gas prices, and other effects.[372]

The FIRM Customers were critical of Dr. Kolbe's assessment of DISCO risks, arguing that the DISCO faces significant risks. Dr. Kolbe claimed that legislated hedges would substantially increase DISCO risk since they effectively reduce GENCO risk. As a result, DISCO cash flows will become more volatile. In response to this argument, the FIRM Customers submitted that the issue of legislated hedges is not a zero sum game. The FIRM Customers argued that the

[367] Marcus, Exhibit 159, p.8; Tr. 5225-5226
[368] Exhibit 159, p.7; TAU-FIRM-13
[369] Tr. p.5234
[370] FIRM.TAU-97; Exhibit 162, p.41-42
[371] Exhibit 159, p.19
[372] Exhibit 159, p.8-9

legislated hedges reduce risks to both the GENCO and the DISCO since both entities are not exposed to an unhedged pool price in the particular environment.[373]

The FIRM Customers also noted that despite Dr. Kolbe's claim that the Distribution function has high risks, TransAlta's 1998 Annual Report provided a more balanced view of Distribution risks. In TransAlta Corporations 1998 Annual Report, Distribution is referred to as low-risk, similar to transmission:

> T&D's [Transmission and Distribution's] low risk profile can be maintained because it is expected to remain largely regulated in Alberta. Growth will be determined principally by the long-term performance of the provincial economy.[374]

The FIRM Customers argued that despite being contradicted by the evidence of TransAlta, Dr. Kolbe potentially exaggerated the distribution risk for particular reasons. The FIRM Customers were concerned that Dr. Kolbe's primary claim appears to be that DISCO fixed costs will increase due to the legislated hedge. The legislated hedges act like increased debt leverage, exposing the DISCO to greater risk in the event demand falls. Thus, in Dr. Kolbe's view, this type of leverage must be compensated through a higher ATWACC or return on equity.

The FIRM Customers responded to Dr. Kolbe's assessment of distribution risk, stating that his position has three significant problems. First, the FIRM Customers argued that Dr. Kolbe failed to consider the shifting of risk from TransAlta as a unified Utility in the old world to wholesale municipal customers. As a result, he has overstated the total risk that is outstanding. Second, TransAlta has not provided empirical data to determine whether the demand risk is material rather than of theoretical concern. Finally, Dr. Kolbe's quantitative analysis of differences in demand risk created by the new regulatory structure has used incorrect parameters.[375] The FIRM Customers submitted that when the quantitative analysis is corrected, it concluded that demand risks in the new and old worlds are approximately equivalent.

The FIRM Customers' first argument was that Dr. Kolbe failed to consider risk off-loading to municipalities in the new world. The FIRM Customers stated that, as demonstrated by Drs. Waters and Winter, Dr. Kolbe's analysis failed to consider that a portion of risk is being shifted away from the regulated utility under the new world. In particular, 23% of entitlements are now held by municipal DISCOs and the TA.[376] Thus, Dr. Kolbe's assumption about moving risks from GENCO to DISCO within a utility such as TransAlta represents a zero-sum game is incorrect. The FIRM Customers concluded that a portion of TransAlta's risk in the old world

[373] Exhibit 159, p.15
[374] Exhibit 105, p.6B
[375] FIRM.TAU-97
[376] Exhibit 162, p.50

has been transferred to the risk of the municipal DISCOs, reducing the overall risk of the regulated utilities taken as a bundle.[377]

The FIRM Customers' second argument dealt with the consideration that TransAlta has refused to provide real data supporting its claim that it needs a significantly higher return to compensate shareholders for demand risks. As a result, the FIRM Customers recommended that the Board should not give any weight to Dr. Kolbe's claim TransAlta DISCO faces a huge demand risk requiring significant compensation.

The FIRM Customers argued that TransAlta did not make available any real data to test Dr. Kolbe's arguments regarding distribution were valid. In addition, TransAlta did not provide any data on its past forecasting performance to support its argument that DISCO demand risk is material. Finally, the FIRM Customers were concerned that TransAlta did not answer the FIRM Customers' questions relating to the magnitude of the demand risk.

For example, in FIRM.TAU-55(m) and (n), the FIRM Customers asked TransAlta questions that were intended to test the accuracy of TransAlta's short-term load forecasts relative to recorded information. The FIRM Customers confirmed that these questions were posed to determine the probability that TransAlta was over/under-forecasting its GRA load forecast based on historical performance and the extent of such variances. In this case, the FIRM Customers noted that Dr. Kolbe's example is based on a 2% reduction in TransAlta demand relative to the amount predicted one to two years in advance. In summary, the FIRM Customers confirmed that it was requesting data to discover the probability that Dr. Kolbe's predictions could be realized, as well as to test the credibility of his evidence.

In response to the FIRM Customers' request, the FIRM Customers stated that TransAlta refused to provide data prior to 1996, based on an argument by the Utility that it considered pre-1996 information was not relevant to the current proceeding. In response, the FIRM Customers argued that the only way to determine the magnitude of this demand forecasting risk is to analyze a reasonable historical period to compare TransAlta's short-term forecasts to what actually occurred. The FIRM Customers suggested an extended historical period was required to determine the long-term probability that TransAlta has been significantly over/under-forecasting its load one or two years in advance.

The FIRM Customers submitted that TransAlta should have provided the necessary data to support its request for a 13.45% return on equity for its DISCO operations (i.e., 260 basis points above its average requested return for the Utility as a whole). Since it has failed to provide the data, particularly the data requested in FIRM.TAU-55 (m) and (n), the FIRM Customers argued that it would be reasonable for the Board to deny TransAlta's request.

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[377] A portion of the risk had already been faced by the municipalities in the past, because TransAlta sold energy to municipalities under different rate structures than the municipalities sold it to their customers. (IPCAA.FIRM-2; see also Exhibit 136, Volume I, p.1-7 to 1-8)

The FIRM Customers' final assertion about Dr. Kolbe's assessment of Distribution risk was that Dr. Kolbe's numerical analysis supporting his demand risk argument is incorrect. In order to demonstrate the increased level of risk due to the legislated hedges, Dr. Kolbe prepared a numerical example that compared the old and new world risk structures. The FIRM Customers noted that Dr. Kolbe's analysis claims to demonstrate that the new world structure of legislated hedges is approximately three times more risky to the DISCO than the old world structure (that is assuming a fixed generation price). In particular, Dr. Kolbe claimed that the new world structure increases the sensitivity of the DISCO to demand.[378]

In response, the FIRM Customers presented Mr. Marcus' corrections to Dr. Kolbe's numerical analysis. First, Mr. Marcus increased the elasticity of pool price with respect to demand from Dr. Kolbe's assumed values (0.5 to 1.0) to actual values calculated from data prepared by TransAlta in the current proceeding. Second, Mr. Marcus corrected Dr. Kolbe's analysis by assuming a higher proportion of variable transmission costs based on TransAlta's most recent Phase II evidence. Finally, Dr. Kolbe's old world analysis was adjusted to reflect the fact the GENCO could offer a fixed price for its own generation, whereas the DISCO still is exposed to risk related to pool prices for independent generation and imports.[379] After all of these adjustments were made, Mr. Marcus concluded that, from the perspective of the DISCO, the old world and new world with legislative hedges have approximately the same level of risk associated with changes in demand.[380] Thus, the FIRM Customers concluded that based on Mr. Marcus' revised analysis, demand risks are relatively unchanged from the old world.

The FIRM Customers claimed that even if Dr. Kolbe's calculations and predictions were accepted as fact, it believed that the compensation for risk is excessive in comparison to the magnitude of the risk. Specifically, the FIRM Customers do not agree with Dr. Kolbe's conclusion that the Distribution function needs a return of 13.45%, yielding an average system return of 10.86%. The FIRM Customers confirmed that by utilizing all of Dr. Kolbe's information (as recalculated in the aggregate in Mr. Marcus' Schedule 1 under the "Kolbe, New World" column, which excludes Mr. Marcus' corrections), the FIRM Customers calculated an average annual loss to the DISCO for a 2% demand reduction to be equal to $9.15 million.[381] After subtracting income taxes at the 43.5% statutory rate, the after-tax loss of income is $5.169 million.[382] TransAlta's rate base in 1999 (net of contributions) is $448.6 million.[383] Therefore, the FIRM Customers concluded that the loss predicted by Dr. Kolbe from a 2% demand reduction is 115 basis points, or 1.15 percentage points, of return on rate base ($5.169 million divided by $448.6 million). .

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[378] FIRM.TAU-97

[379] Exhibit 159, p.16-18, Schedule 1

[380] Exhibit 159, p.19; Tr. p.5256

[381] TAU-FIRM-29

[382] Exhibit 13, Vilbert, Table MJV-10

[383] Exhibit 13, section 4.1, p.4

In comparison to the calculated potential loss related to demand risk, the FIRM Customers noted that Dr. Kolbe's recommended increase in the DISCO rate of return over the system average return is 2.59% (13.45% minus 10.86%), with 42% book equity.[384] This translates into 109 basis points, or 1.09 percentage points, of extra return on rate base. Thus, the FIRM Customers asserted that Dr. Kolbe is asking the ratepayers to pay a return on equity in each and every year that is 94% of the loss Dr. Kolbe believes the DISCO would realize if it experienced a 2% reduction in demand from forecast levels (109/115 basis points). As a result, the FIRM Customers were critical of the fact that shareholders would receive an insurance premium (through a higher rate of return) that represents 94% of the shareholders' potential risk or loss under adverse conditions. Based on the high cost of this form of insurance, the FIRM Customers argued that it membership representing a large number of TransAlta's ratepayers, would instead find it beneficial to self-insure against this risk through deferral accounts.

The FIRM Customers confirmed that, when calculated correctly, the average annual loss to TransAlta-DISCO as a result of a 2% reduction in demand is estimated to be only $1.65 million (before tax), or 21 basis points of after-tax return.[385] Consequently, the FIRM Customers concluded that this significantly lower result demonstrates that Dr. Kolbe's risk compensation is very excessive.

The FIRM Customers disputed Drs. Waters and Winter's claim that the DISCO should be deemed to be 110-140% as risky as the GENCO (with a focus on 125%),[386] arguing that the relative risk of the DISCO has been overstated. However, Drs. Waters and Winter overstated the DISCO risk by a smaller amount than TransAlta since they recognized that a significant portion of GENCO risk has not been transferred to regulated DISCOs. In the FIRM Customers' view, Drs. Waters and Winter's recommendations are overstated for two reasons. First, they did not take into account the DISCO deferral account recommended by Mr. Drazen, which would effectively reduce DISCO risk. Second, their DISCO recommendations are focussed primarily on the 1999-2000 period, since they are based on Dr. Kolbe's basic analysis.[387] Recognizing that investors take a more long-term perspective and given the consideration that the DISCO's risk position will be significantly reduced after 2000, the FIRM Customers concluded that it would be more reasonable to focus on the lower end of Dr. Waters and Winter's recommended range of risk (i.e., 110-120% of the GENCO risk).[388]

The FIRM Customers supported the use of deferral accounts to manage the risks of the GENCO and DISCO with respect to volatile pool prices.[389] The FIRM Customers recommended that the

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[384] Exhibit 159, p.4
[385] Exhibit 159, Schedule 1, "New World Hedged" column
[386] Exhibit 162, p.50
[387] Exhibit 162, p.50
[388] Exhibit 162, p.41
[389] FIRM Customers Argument, section 2.2

Board should factor in the use of these deferral accounts, taking them into account when establishing the return by function.

The FIRM Customers also submitted that the overall return differentials by function are relatively modest. In terms of specific functions, the FIRM Customers expressed the view that Transmission is less risky than the average, with risk related to Distribution wires ownership being a maximum of 25 basis points riskier than transmission (due to rate design issues).

The FIRM Customers argued that the equity percentages of gas local distribution companies are instructive in analyzing the near-term risk of Distribution wires ownership bundled with a retailing system that is not very competitive, but without brokerage risk.[390] The FIRM Customers submitted that these type of companies are analogous to electric Distribution wire owners since they face very little brokerage risk. Brokerage risk is negligible since gas costs are either covered by deferral accounts or are the direct responsibility of the customer.

In terms of retailing risk, the FIRM Customers recommended that retailing risks (other than brokerage) should not be given significant weight at this time for several reasons. First, retailing is currently not competitive. Second, the Alberta Government has provided assurances that any DISCO costs which become stranded as a result of a future move to competitive retailing will be ultimately recoverable. Finally, the FIRM Customers stated that wire owners will continue to exercise a monopoly in the potentially more competitive metering area through to 2006.[391]

The FIRM Customers claimed that brokerage risks are also limited with the recommendation that no more than 50 basis points should be allowed for these risks. This premium would be contingent on a rejection of the DISCO pool price balancing or deferral account recommended by the FIRM Customers and IPCAA. However, if a balancing account is accepted to protect against pool price fluctuations, the FIRM Customers submitted that a brokerage allowance of 25 basis points would be more appropriate.

When setting a DISCO return, the FIRM Customers recommended that the Board should separate the wires return from an allowance for retailing and brokerage. As a result, the Board would be able to back out the retail and brokerage costs from the Distribution Access Tariff and allocate those costs properly to customer classes in future Phase II proceedings.[392] The FIRM Customers also recommended that it would be worthwhile for the Board to identify those costs that may be temporary due to the existence of legislated hedges.[393] Finally, the FIRM Customers suggested that the appropriate way to deal with brokerage risk compensation is to establish a separate allowance for the area in the distribution revenue requirement, rather than bundling it in

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[390] Exhibit159, p.7; TAU.FIRM-12; TAU.FIRM-13
[391] Exhibit 159, p.11; IPCAA.FIRM-6
[392] Exhibit 159, p.13-15
[393] Exhibit 159, p.14

with the rate of return for wires.[394] Applying this methodology would clarify the Board's decisions when it sets the Distribution Access Tariffs and Phase II class revenue requirements.

In its reply argument, the FIRM Customers stated that the arguments submitted by the Utilities on business risk by function are sparse. For example, in TransAlta's case, the Utility confirmed that it may have overstated the short-term risk faced by distribution companies in Dr. Kolbe's evidence, given the tight pool market in 1999-2000.[395] However, TransAlta claimed that the DISCO risk is higher on a long-term basis, justifying Dr. Kolbe's calculations.[396]

In response, the FIRM Customers submitted that the long-term higher DISCO risk identified by TransAlta is not as large as TransAlta suggests. The FIRM Customers noted TransAlta Corporation's statement that Transmission and Distribution's low risk profile can continue since it is expected to remain largely regulated in Alberta.[397] In addition, as discussed in Mr. Marcus testimony and the FIRM Customers' argument, retailing risks will be unregulated (except for the Regulated Rate Option), brokerage for the Regulated Rate Option will be hedged commercially, and stranded costs in metering and billing will be covered by ratepayers.[398]

Position of COCI

The COCI presented a discussion of business risks in the Distribution sector introduced by the EU Act. The Distribution sector has two functions: (1) the delivery of electricity along distribution wires (at lower voltage than along transmission wires); and (2) the retailing function, which includes the payment of supply costs (pool prices), hedges and transmission and the recovery of those costs from customers. The retailing function also includes metering, billing and providing customer service.

Under the EU Act, the retailing function of the Distribution sector will be open to competition. In 2001, the billing function will be open to competition; in 2006, the metering function will be open. Furthermore, the regulatory plans allow for competition among intermediaries between the power pool and consumers. The access by these intermediaries to distribution wires will be set at a regulated access tariff.

Drs. Waters and Winter submitted that the prospect of future competition in the retailing function does not present additional risk to the Distribution wire function. First, customers still need to use the wires. Next, the retailing revenues in distribution will be affected by future competition. However, in a competitive environment, capital will enter the industry only to the extent that the new capital is expected to earn a fair, risk-adjusted rate of return. In addition, incumbent firms have some advantages over prospective entrants in terms of knowledge of the industry,

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394 Marcus, Tr. p.5223
395 TransAlta Argument, p.45
396 TransAlta Argument, p.45-46
397 Exhibit 105, p.6B
398 FIRM Customers Argument, p.14-15, 21

knowledge of customers and a reputation for providing very reliable service. As a result, Drs. Waters and Winter asserted that these firms should earn a return on capital in the servicing function that is not less than the rate of return earned by new entrants. Thus, efficiently managed incumbent utilities should be able to earn more than a fair, risk-adjusted rate of return on capital in the retailing function. In summary, Drs. Waters and Winter concluded that entry into retailing should not pose a substantial risk to distributors. In addition, the EU Act will provide for a five-year transition period to full retail competition.

A second source of risk that Drs. Waters and Winter discussed is the transfer of operating leverage from the Generation sector to the Distribution sector. During 1999 and 2000, the Distribution function is required to support the fixed costs of existing generators through the transfer payments (reservation payments). While these are passed on to ratepayers, owners of Distribution assets are exposed to the consequences of the higher operating leverage in the form of higher risks. Drs. Waters and Winter emphasized that this represents a pure transfer of risk from the Generation sector to the Distribution sector, as opposed to the creation of a new risk within the electricity industry. However, after 2000, the distributors will not bear the risk resulting from increased leverage since the generator costs will be paid for by the PPA purchasers.

For 1999, Drs. Waters and Winter compared the magnitude of the obligation to pay reservation payments (representing the fixed costs related to the transfer of risk from the Generation sector to the Distribution sector with the obligation to pay interest to debt holders and dividends to preferred shareholders, which represent the total source of financial risk. For TransAlta Generation, the combined interest payments and preferred share dividends for 1999, as per the Schedule of Return contained in the TransAlta Application, is $84 million, representing TransAlta's financial risk. By comparison, the aggregate reservation payments to TransAlta's Generation assets is forecast to be $564.2 million in 1999. As a result, Drs. Waters and Winter concluded that the transfer of risk from Generation to Distribution is substantial.

At the same time, Drs. Waters and Winter submitted that the transfer of risk from generation to distribution is, to a significant extent, a transfer of risk away from the vertically integrated utility companies. Specifically, 23% of the reservation payments are paid by non-vertically integrated municipal distribution utilities, based on 1999 forecasts.[399] Thus, Drs. Waters and Winter concluded that a significant portion of the risk transfer of reservation payments represents a shift of risk away from the investor-owned utilities.

Drs. Waters and Winter identified three sources of protection against risk at the Distribution level that the Board should consider in assessing the overall risk of the integrated utilities. First, the medium-term exposure of the Distribution wire function to changes in demand or costs is offset to a large degree by the monopoly position of Distribution wire-owners. In addition, if demand does not rise as fast as expected, or costs increase, the regulated distributor wire-owners

399 This figure excludes EPGI, whose subsidiaries both pay and receive reservation payments.

can apply for a rate hearing in order to rebalance the relationship between prices and costs. Furthermore, the substantial potential earning power of the Distribution function provides the distributors with a large cushion, effectively insulating the firms from demand and cost risk. Drs. Waters and Winter commented that the transfer of risk from Generation to Distribution results in a portion of industry risk remaining in a segment that will continue to be regulated under the traditional rate of return mechanism. In contrast, the distributor retailing function will substantially absorb the risk transferred from generators.

Second, Drs. Waters and Winter submitted that the distributors are protected from the risk of earning less than a fair return on capital in the retailing segment of their operations. As explained earlier, the existing distributors have off-balance sheet assets or cost advantages that give them an overall advantage over new entrants that are starting up in retailing. In addition, prospective entrants will not enter into the market if the anticipated rate of return is less than fair.

Third, Drs. Waters and Winter stated that the Distribution companies are proposing to pass through the pool price variations to customers. Under the new system, electricity purchasers will be offered the opportunity to purchase electricity at rates that vary with the pool price, rather than paying guaranteed rates. Drs. Waters and Winter claimed that substantial volumes of energy are expected to be sold at variable prices.

In the future, purchasers will be able to hedge these risks using financial instruments such as forward contracts, futures markets or options on futures markets. In terms of business risk, the implication of the variable price contracts is that the substantial transfer of risk from generators to distributors under the EU Act will simply be passed on to purchasers. Drs. Waters and Winter noted that transferring price risk to final purchasers represents an efficient result since purchasers will then continually face the "correct" prices or proper opportunity costs. Related to this outcome, the purchasers have the ability to absorb or hedge the risks.

In terms of an assessment of the overall Distribution risks relative to generation risks, Drs. Waters and Winter submitted that the Distribution wires function is less risky than Generation. In contrast, Distribution retailing is substantially more risky than generation assets, largely as a result of the transfer of risks from the Generation to the Distribution sector. In summary, Drs. Waters and Winter stated that a reasonable estimate of the relative risks is that the combined distribution functions are 10 to 40% more risky than Generation assets.

Position of IPCAA

In order to analyze risk differentials, IPCAA divided the Distribution sector into the Distribution Wires function and Distribution Retailing function. IPCAA explained the reason for splitting distribution into two components is that the inherent business risk on the Wires function is quite different than on the Retailing (or supply aggregation) function. Moreover, whereas Wires will continue to be a regulated business into the future, Retailing will change significantly over the next two years.

IPCAA submitted that the risk on DISCO-Wires is somewhat higher than that for transmission. In support of this statement, IPCAA stated that the DISCO does not have a guaranteed revenue payment, but instead depends on the number of customers and their usage. At the same time, this risk can be reduced by recovering a larger portion of the Wires cost through fixed monthly charges (as AE-DISCO and TransAlta-DISCO have proposed to do in their recent Phase II filings). IPCAA also noted that DISCO-Wires have a higher proportion of their cost of service in operating costs as opposed to capital-related costs, resulting in higher potential risks since actual costs may vary from projected costs. For example, TransAlta-DISCO's operating costs represent 35% of proposed total 1999 costs.

IPCAA submitted that DISCO Retailing has the highest risk. IPCAA explained that this arises from the fact that the DISCO incurs a high fixed cost (primarily Reservation Payments), which is recovered on a variable basis (depending on the rate design) from customers. In addition, to the extent the DISCO has unhedged load, the DISCO's Retailing function is subject to forecast risk related to Pool Price. However, IPCAA stated that this risk can be mitigated by deferral accounts and Pool Price flow-through rates. With regard to this recommendation, IPCAA noted that a deferral account on unhedged energy was used by TransAlta-DISCO in the 1998 Negotiated Settlement.

Position of IPPSA/SPPA

IPPSA/SPPA noted that Dr. Kolbe conceded that the use of a deferral type mechanism would reduce risk to the DISCO side of the operation.[400] Thus, IPPSA/SPPA argued that to the extent the Board accepts IPPSA/SPPA's recommendation for the implementation of deferral accounts, then the Board should also adjust the Utilities' capital structure and rate of return downward accordingly. In response to the views of the Utilities on the subject of deferral accounts, IPPSA/SPPA submitted that the reason why the Utilities are opposed to the use of deferral accounts is that they may subsequently receive a downward adjustment in their capital structure and rate of return.

Position of TransAlta

Dr. Kolbe provided evidence for TransAlta on differential risk by function. Based on the evidence and ignoring any risk transfers, he concluded that the Distribution function was less risky than Generation but more risky than Transmission. As a result, Dr. Kolbe recommended an ATWACC of 7% for Distribution, which is equivalent to the bundled utility value of 7% estimated by Dr. Vilbert.

Based on the risk transfer from Generation to Distribution as a result of legislated hedges, Dr. Kolbe recommended an adjustment of 1% for distribution with the result that he increased the ATWACC for Distribution would be increased to 8%. The adjustment for distribution reflecting the risk transfer is significant since the legislated hedges are supported by a much smaller base of Distribution assets. Thus, a major increase in the after tax weighted average cost

[400] Tr. p.5001-5002

of capital for Distribution is required to maintain the overall ATWACC of 7% for the bundled utility. The 8% ATWACC percentages translates into a common equity ratio of 56.58% for DISCO, assuming an integrated utility common equity percentage of 42% and a constant cost of equity across the lines of business.[401]

Dr. Kolbe presented lower estimates of the risk transfer in his rebuttal testimony as a result of the extremely tight electric market conditions in the near term. He estimated that the risk transfer may be as low as a 0.50% risk increase for Distribution, resulting in an ATWACC of 7.5% for the DISCO function.

TransAlta responded to the FIRM Customers' assertion that the risks of the "wires" and "retailing and brokerage" parts of Distribution must be analyzed separately. TransAlta argued that the Board did not direct the parties to separate the Distribution function into sub-functions. TransAlta noted that the FIRM Customers were alone in requesting that the Board separately analyze the costs of capital of the sub-functions of Distribution. As a matter of interest, TransAlta also noted that no party, including the FIRM Customers , proposed separate costs of capital for any sub-functions of Distribution. As a result, TransAlta submitted that there is no need for this type of exercise in the current proceeding.

TransAlta was critical of the FIRM Customers' arguments against the Utility's specific recommendations relating to the relative risk and cost of capital of Distribution. In response to the FIRM Customers' characterization of Dr. Kolbe's adjustment for the effect of the legislated hedges as being "extreme", "drastic" and "huge", TransAlta stated that Dr. Kolbe believed his adjustments were "modest" given the potential of the legislated hedges to transfer risk from Generation to Distribution.[402] TransAlta further claimed that the impact of any risk transfer on the Distribution function is unavoidably magnified by the fact that Distribution must absorb the increased risk on a much smaller base of assets relative to Generation assets, in order for the overall cost of capital of the Utility to remain correct. Thus, the relevant issues are not the language used to characterize the transfer, but whether the legislated hedges do transfer some risk and how to respond to the transfer to the extent it is determined to be real.

TransAlta responded to the FIRM Customers' argument that the legislated hedges reduce the risk of both Generation and Distribution relative to a scenario in which both faced an unhedged pool price.[403] TransAlta argued that the statement against Dr. Kolbe's evidence was irrelevant in relation to the relative risk of Distribution and Generation in 1999 and 2000. In particular, TransAlta stated that the benchmark samples used to estimate the cost of capital should be the regulated utilities, not the companies operating unhedged in markets where Generation is deregulated. Thus, Dr. Kolbe made the appropriate comparison, analyzing how the legislated

[401] Table No. ALK-2 Revised Panel A:1999
[402] Dr. Kolbe's Rebuttal Testimony, Section I
[403] FIRM Customers Argument, Section 2.3, p.15

hedges affect the relative line-of-business risks of the sectors of a still-regulated utility relative to those that would exist without the legislated hedges.

In response to the FIRM Customers' claim that Dr. Kolbe failed to consider the shifting of risk from TransAlta as a regulated utility in the old world to municipal DISCOs in the new world, TransAlta's stated that its relative line of business shares are very close to the overall shares in the Province of Alberta.[404] Based on this consideration, Dr. Kolbe's rebuttal testimony provided calculations[405] demonstrating the impact of using Provincial relative line of business shares rather than TransAlta's shares. As a result of this exercise, Dr. Kolbe concluded that the differences are not material relative to the intrinsic uncertainty in estimating the cost of capital.

TransAlta also disagreed with the FIRM Customers' statement that Dr. Kolbe used incorrect parameters for a numerical example designed to analyze the potential impact of the legislated hedges.[406] TransAlta noted the FIRM Customers' statement that when corrections were made to the numerical example, it concluded, demand risks in the new and old worlds are approximately equivalent. TransAlta confirmed that the FIRM Customers' statement was similar to Dr. Kolbe's original conclusion for plants expected to operate beyond the unit obligation amounts, in the range where the legislated hedges do not provide a guarantee to the generator.[407] TransAlta also submitted that the FIRM Customers' changes to Dr. Kolbe's original example does not alter the conclusion that the legislated hedges are valuable for plants not expected to operate beyond their UOAs.

In its reply argument, TransAlta expressed a concern that the FIRM Customers presented for the first time calculations, which relied on Mr. Marcus's testimony, that attempted to demonstrate that the ATWACC risk transfer produces a disproportionate adjustment in response to a demand shift of 2%.[408] TransAlta was critical of the FIRM Customer's presentation since the Utility was not in a position to be able to cross-examine a sponsoring FIRM Customers witness and would not be able to respond to cross-examination by the FIRM Customers on this issue.

TransAlta noted that Dr. Kolbe agreed that due to the current tight supply situation, it is possible that there is less risk transfer in the near term than would exist in the longer term, were the legislated hedges to continue. Dr. Kolbe also noted, however, that it is not possible that no risk transfer is occurring. As a "tie-breaker," Dr. Kolbe suggested that the Board might want to take Mr. Marcus's advice to look to the longer run trend for the cost of capital for Distribution in order to minimize the changes that are needed between 2000 and 2001. In line with this suggestion, TransAlta responded that to the extent the Board may elect to take this approach, Section IV, Part D of Dr. Kolbe's rebuttal testimony demonstrates that the cost of capital of the

[404] FIRM Customers Argument, Section 2.3, p.16
[405] Tables ALK-R5 to ALK-RT8
[406] FIRM Customers Argument, Section 2.3, p.16
[407] Section IV, Part B of Dr. Kolbe's Rebuttal Testimony
[408] FIRM Customers Argument, Section 2.3, p.19

Distribution function will be going up following deregulation. Thus, based on the evidence, TransAlta recommended that in this instance it would be better to adopt Dr. Kolbe's original recommendation for the amount of cost of capital risk to be transferred from Generation to Distribution.

With respect to the FIRM Customers' specific recommendations in the Distribution area, TransAlta contended that the group's recommendations in this area are outside the scope of the information the Board requested and, if implemented, would shift risk to all customers.[409] First, the FIRM Customers requested that separate risk determinations be presented by sub-function for Distribution. However, TransAlta responded that the FIRM Customers never offered line-of-business cost of capital recommendations for the sub-functions, nor did it present their relative size in the overall aggregate risk of the Distribution function.

Second, the FIRM Customers recommended developing a new deferral account to respond to the effect of volatile pool prices. In response to this recommendation, TransAlta submitted that the introduction of a deferral account does not eliminate the risks, it simply shifts the risks directly to all customers. As an alternative, TransAlta submitted that rates could be set at a level that would allow the Utilities to bear the risk instead. In addition, TransAlta commented that the FIRM Customers did not address the possibility that, in comparison to the group's members, some customers may be less able or less willing to bear this risk. In summary, TransAlta concluded that it does not believe a deferral account is the appropriate way to deal with the risk that has been identified.

Board Findings

The Board notes that some parties presented a discussion of Distribution business risks by components, that is Distribution wires, retailing and brokerage, as a result of the different business risk across sub-functions. The Board further observes that the FIRM Customers submitted that Distribution risks must be divided into separate components to prepare for the changes that are expected to occur in regulatory structure in 2001. However, the Board notes that TransAlta submitted in its argument that none of the parties, including the FIRM Customers, have proposed line-of-business cost of capital recommendations for the sub-functions of Distribution.

The Board observes that to the extent that the COCI sub-divided Distribution risk in its evidence, it came to the conclusion that the combined Distribution function risk (DISCO Retailing plus DISCO Wires) has greater risk than GENCO risk. This ranking of risk is in line with the Board's relative ranking of DISCO risk. Thus, the Board notes that it is possible to arrive at the same conclusion about the ranking of DISCO risk, whether or not one decides to sub-divide Distribution risk into components.

[409] FIRM Customers Argument, Section 2.3, p.20-21

In summary, the Board does not accept the argument that it is necessary to separate the components of Distribution risk in the current proceeding. The time frame for competition within the DISCO sector is beyond the period under consideration in the present proceeding. However, the Board considers that it is worthwhile and of interest to discuss the business risks of the components of Distribution, even though competition will not commence for the Distribution sector until 2001, when the retailing function will be open to competition. In particular, it is important to note that the business risks for the DISCO function as determined in this proceeding will not be applicable or transferable to the DISCO Wires function in the upcoming Distribution Tariff and Regulated Rate Option proceedings.

With respect to an overall assessment of DISCO business risk, the Board notes that TransAlta and the COCI agreed that Distribution risk is the highest risk function of the electric Utilities. In this regard, the Board notes that the major reason given by the parties for the high level of risk for the DISCO function is the transfer of risk from the Generation sector to the Distribution sector.

In particular, the Board notes the COCI's statement that during the 1999 and 2000 period the Distribution function is required to support the fixed costs of existing generation through transfer payments, in the form of reservation payments. In essence, this risk transfer represents a transfer of operating leverage from the GENCO sector to the DISCO sector. Thus, the Board agrees with the COCI's assessment that while the costs of the transfer payments are passed on to ratepayers, the DISCOs bear the consequences of the higher operating leverage in the form of higher risks.

Furthermore, in terms of this pure risk transfer, the impact of the transfer is magnified due to the fact that the reservation payments that are being paid out to the GENCO sector are in turn being supported by a relatively smaller base of DISCO assets. For example, in the case of TransAlta, TransAlta-DISCO represents 15% of the Utility's aggregate rate base, whereas TransAlta-GENCO represents 62% of the Utility's total rate base. Thus, the Board agrees with TransAlta's statement that the impact of any risk transfer is unavoidably magnified by the consideration that the DISCO must absorb the higher risk on a much smaller base of assets in comparison to GENCO assets.

At the same time, the Board acknowledges the FIRM Customers and COCI's statement that some risk off-loading to municipalities is occurring in the new world. Since 23% of reservation payments are being paid by non-vertically integrated municipal distribution utility companies and the TA (based on 1999 forecasts), this factor partly reduces the overall risk of the investor-owned integrated Utilities.

However, to put the overall issue of the transfer of risk into perspective, the Board notes the COCI's comments about the magnitude of the transfer payments. The aggregate reservation payments received by TransAlta's Generation assets is forecast to be $564.2 million in 1999. From the perspective of the DISCO, TransAlta-DISCO is required to pay aggregate reservation

payments of $468.8 million in 1999 to TransAlta-GENCO, AE-GENCO and EPGI.[410] The Board notes that, with respect to TransAlta-DISCO, this obligation represents 38% of the TransAlta-DISCO's revenue requirement and 68% of the mid-year rate base of $693 million (including customer contributions and no-cost capital) for 1999. The Board also notes that the proportion of revenues that are collected on a variable basis is much higher for TransAlta-DISCO than for TransAlta-GENCO thereby increasing the relative risk of DISCO compared to GENCO. The Board finally notes that a major conclusion of COCI with respect to the transfer of risk is that by any measure, the transfer of risk from Generation to Distribution is substantial.

In conclusion, based on the significant transfer of operating leverage from the GENCO sector to the DISCO sector, the relatively small base of DISCO assets supporting the payments being made to the GENCO sector, the overall magnitude of the reservation payments that have to be paid out by the DISCO sector, and the variability of DISCO revenues, the Board agrees with COCI's conclusion about the transfer of risk to the DISCO. The Board believes that the transfer of risk to the DISCO is significant, even under current tight market conditions.

Accordingly, the Board concludes that the risk of the Distribution function is relatively high and significantly higher than the risk of the integrated utility. As a result, the capital structure for the DISCO should be significantly adjusted to reflect the relatively high level of risk within the Distribution function.

At the same time, the Board notes that some of the parties recommended the use of deferral accounts or Pool Price flow-through rates to mitigate the risk of the Distribution function. The Board has approved a pool price deferral account for the DISCO function elsewhere in this Decision.[411] The Board believes that with the introduction of DISCO pool price deferral accounts, DISCO business risk will be mitigated somewhat.

Thus, following the initial upward adjustment in the capital structure for the DISCO, based on the Board's general conclusions about DISCO business risk, the capital structure should then be moderately adjusted downward, to reflect the reduction in risk from the pool price deferral account and the modest shift to Pool Price flow-through rates. However, as a summary, the Board notes that after incorporating the impact of the deferral account with the Board's general conclusions about DISCO risk, the Board remains of the view that the final overall risk of the DISCO is significantly higher than the risk of the integrated utility.

The combined risk-related adjustments is large enough that the DISCO capital structure should be significantly above the average capital structure for the integrated utility. Therefore, in terms of a common equity ratio, the Board would assign to the DISCO a common equity ratio differential in the order of 1350 basis points (13.5%) higher than the integrated utility common equity ratio.

[410] Drazen Evidence, Vol. IV, Section 3, p.1
[411] See Board Findings in DISCO Deferral Accounts Section 3(c)

Accordingly, based on the Board's assessment of business risk of the DISCO for 1999 and 2000, the Board has determined that an acceptable range of common equity ratios for an investor-owned DISCO is in the range of 53.5-55.5%. This target range provides a mid-point of 54.5%, reflecting the significantly higher risk of the DISCO relative to the integrated utility. The Board notes that given an allowed common equity ratio of 53.5-55.5% and an equity rate of return of 9.00-9.50% (determined in the Return on Equity section), TransAlta-DISCO's before tax interest coverage will be 5.52-5.75 times for 1999 and 6.23-6.50 times for the year 2000. On an after-tax basis, TransAlta-DISCO's interest coverage will be 2.93-3.03 times for 1999 and 3.01-3.12 times for the year 2000.

Taking all of the above into consideration, the Board considers that the following capital structure (i.e., investor supplied funds; excluding no-cost capital and contributions) for TransAlta-DISCO will reflect the business and financial risks that are faced by the Utility during the 1999-2000 period:

TransAlta-DISCO Capital Structure

Board Approved

	Common Equity	Preferred Equity	Total Equity	Debt
TransAlta DISCO 1999-2000	53.5-55.5%	9.5%	63.0-65.0%	35.0-37.0%
Mid-point	54.5%	9.5%	64.0%	36.0%

Accordingly, the Board considers that a common equity ratio of 53.5-55.5% (i.e., midpoint of 54.5%) is appropriate for TransAlta-DISCO for the test years 1999 and 2000.

(i) Return

The Board in this section will set out its findings respecting the cost rates for debt, preferred and common equity.

(1) Cost of Debt

The mid-year cost of debt normally consists of the cost of prudently incurred embedded debt plus new debt issues at the rate they are forecast to be issued.

3. GENCO/TRANSCO/DISCO
(i) Return

Position of TransAlta

In evidence, TransAlta forecast that it would issue $80 million of Series X secured debentures at a rate of 6.750% in 1999. In 2000, TransAlta forecast that it would issue $89 million of Series Y and $100 million of Series Z secured debentures, both at a rate of 7.000%. TransAlta also included in its embedded cost of debt the amounts to be refinanced in both years. The mid-year amounts of short-term debt were forecast to be $137.2 million in 1999 and $97.8 million in the year 2000. TransAlta forecast the rate for its short-term debt to be 6.500% in both test years. TransAlta forecast the mid-year cost of debt to be 8.191% for 1999 and 7.737% for 2000.

In reply argument, TransAlta disagreed with the proposal of ENMAX that new debt costs should bear rates of 5.5% to 5.6% for new 10-year issues or 6.2% for new 20 to 30 year issues. TransAlta submitted that this issue had been fully dealt with in ENMAX.TAU-58(a). Concerning the assumed term, TransAlta assumed debt issues with long terms, recognizing that the average remaining duration of TransAlta's debt is some 4 years. TransAlta submitted that four years was relatively short considering the long lives of the assets financed. TransAlta considered it prudent to issue debt with longer terms to take advantage of the circumstance of long-term interest rates at historic lows.

With respect to the interest rate forecast for new debt issues, TransAlta submitted that these forecasts were based on the best available information at the time of TransAlta's Application. The forecast interest rates were based upon the 5.7% August, 1998 consensus forecast for 10 year bonds. TransAlta had added to this various premiums for a 20-year issue, for the TransAlta credit spread, for issue costs and issue costs amortization and for anticipated market volatility. A further 0.25 % was added for the 2000 issue to account for market volatility and the risk of increased forecasting error for later issues.

TransAlta considered that ENMAX had used subsequently available information selectively. TransAlta considered that this was inappropriate and unfair. TransAlta submitted that its proposed new long-term debt costs were reasonable and should be approved by the Board.

Position of EPGI

EPGI forecast no new debt issues in the test years. EPGI forecast embedded cost of debt of 9.917% for mortgage debt and 10.200% sinking fund debt for the year 1999. Adjusted for net proceeds and mid-year, EPGI forecast the mid-year cost of embedded debt to be 10.22% for the year 1999. EPGI forecast embedded cost of debt of 9.852% for mortgage debt and 10.193% sinking fund debt for the year 2000. Adjusted for net proceeds and mid-year, EPGI forecast the mid-year cost of embedded debt to be 10.19% for the year 2000.

In argument, EPGI submitted that the applied-for embedded debt costs were fully supported in the evidence and should be accepted by the Board. EPGI noted that no new long-term debt issues are contemplated for either 1999 or 2000 and no party took issue with EPGI's cost of debt.

3. GENCO/TRANSCO/DISCO
(i) Return

In reply argument, EPGI noted that ENMAX's argument stated that EPGI had not included short-term debt in its capital structure. ENMAX considered that EPGI should earn a blended long-term debt/equity rate of return on capital whose cost included the lower cost of short-term debt. In support of its position, ENMAX quoted Dr. Bridgeman's statement that the short-term debt balances are not significant and arise in the course of normal business From this, EPGI noted that ENMAX took the position that, when short-term debt is part of the "normal business," it should be included in the capital structure.

EPGI considered that ENMAX had misconstrued Dr. Bridgeman's evidence. EPGI stated that normal business practice was to build up short-term debt balances and refinance when those balances are sufficient to justify a new issue of long-term debt. EPGI noted that equity was continually refinanced by the reinvestment of retained earnings. EPGI submitted that there was no evidence to support the suggestion that EPGI either had or intended to maintain substantial short-term debt balances rather than refinance such balances in the normal course of business.

EPGI noted that the Board frequently excluded short-term debt from the forecast actual capital structures. in recognition of the fact that short-term debt balances are refinanced in the normal course of business. EPGI cited Decisions E93053, E92039, E93004, E94001, E91093, C85250, E83065, E83074, E87002, E88018, and E91094 as precedents. This treatment of short-term debt was consistent with the proposition that the long-term cost of the short-term capital is the average cost of total capital. EPGI noted that the Board had stated, concerning Edmonton Power, EPGI's predecessor:

> The Board generally considers that short term debt is not permanent capital and should not be considered as capital deemed to be financing the rate base.[412]

EPGI noted that neither the capital structure recommendations of Dr. Evans and Ms. McLeod respecting EPGI and EPTI nor the capital structure recommendations of Drs. Waters and Winter respecting TransAlta were made in the context of capital structures that included short-term debt. EPGI speculated that the higher indicated financial risks might have caused these witnesses to make upward adjustments to their recommended rates of return on common equity, had short-term debt been included in these capital structures. EPGI noted that ENMAX chose not to examine any of these witnesses on the effect of short-term debt on their recommended rates of return. EPGI submitted that adoption of ENMAX's proposal would leave the Board with no useful rate of return recommendation from any expert other than Drs. Kolbe and Vilbert, whose recommendations are independent of capital structure over a broad range of common equity ratios.

EPGI considered that ENMAX's rationale for its short-term debt proposal was based on Exhibits 31 and 32. EPGI considered that it had demonstrated in Section 6.4 of its reply that the analysis in Exhibits 31 and 32 was incorrect, demonstrating that ENMAX's view was insupportable.

[412] Decision E83130, page 48

A further reason given by ENMAX for including short-term debt in EPGI's capital structure was the existence of a difference between rate base and capitalization. However, Mr. Vaasjo, witness for EPGI/EPTI, reconciled the rate base/capitalization difference.

EPGI noted that the City of Calgary (Calgary) made a similar proposal respecting the difference between rate base and capitalization in Canadian Western Natural Gas Company's (CWNG) 1993 GRA. Calgary also noted that CWNG uses short-term debt as bridge financing. Calgary's proposal was based on short-term debt sometimes being used to finance the rate base, since CWNG's capitalization was less than rate base. EPGI noted that the Board, in Decision E93004, rejected Calgary's proposal. EPGI submitted that the Board should similarly reject the ENMAX proposal in these proceedings. EPGI considered ENMAX's proposal to be even less reasonable than Calgary's proposal in the CWNG case because ENMAX would now have the Board assign a 0% cost rate to the rate base/capitalization difference.

Finally, EPGI noted that the City of Calgary Electric system (ENMAX's predecessor) excluded short-term debt from its own capital structure in the 1996 transmission proceeding.

Position of EPTI

In evidence, EPTI forecast that it would issue $45 million, which was later revised to $40 million,[413] of debt at a cost rate of 7.300% in 1999. EPTI did not include short-term debt in its embedded cost of debt for either test year. EPTI forecast the year-end cost of mortgage debt to be 9.063% and the year-end cost of sinking fund debt to be 12.408% for 1999. EPTI forecast the year-end cost of mortgage debt to be 8.951% and the year-end cost of sinking fund debt to be 12.401% for 2000. Including amortized expenses and net proceeds, EPTI forecast the mid-year cost of debt to be 10.03% for 1999 and 9.43% for 2000.

EPTI applied for approval of embedded cost of debt of 10.08% for the year 1999 and embedded cost of debt of 9.44% for the year 2000. EPTI noted that the 1999 and 2000 figures reflected a new debt issue of $40 million in 1999. EPTI submitted that the debt costs were fully supported in the evidence and should be accepted by the Board. EPTI noted no party had taken issue with EPTI's cost of debt.

In reply argument, EPTI noted that EPGI's reasons for exclusion of short-term debt from the EPGI capital structure and EPGI's analysis of Exhibit 33 apply equally to EPTI.

With respect to ENMAX's comments on EPTI's applied-for cost of debt, EPTI noted that ENMAX was mistaken as the amount of the issue was $40 million, not $45 million. EPTI stated that there existed patent errors in ENMAX' argument. Furthermore, ENMAX's argument was not supported by the opinion of any expert in these proceedings.

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[413] Exhibit 37

EPTI noted that the 5.25% yield on long-term Government of Canada bonds used in this part of ENMAX's argument was understated. In comparison, the COCI argument concluded that the appropriate yield on long-term Government of Canada bonds was 5.5-5.75%. EPTI noted that, at another part of its argument, ENMAX agreed with the COCI that the range of the risk-free rate was 5.50 to 5.70%. EPTI noted that ENMAX did not explain these inconsistencies.

EPTI submitted that ENMAX's argument confused the yield difference between long-term Government of Canada bonds and ten-year bonds with the yield difference between long-term Government of Canada bonds and ten-year and greater term bonds. EPTI notes that ENMAX accepted the 40 basis points as the yield difference between long-term and ten-year bonds, which was used by EPTI to develop its forecast cost of debt. EPTI considered that ENMAX was further confused when it added only the 25 basis points to arrive at its understated 5.25% result.

EPTI considered ENMAX's 120 basis points spread, including issue costs, was also understated. The bond yields on which ENMAX relied to draw this conclusion were yields on outstanding debt, not cost rates for newly issued debt. EPTI submitted that issue costs were, by definition, excluded from the calculated spreads. Furthermore, EPTI noted that the data on which ENMAX relied are those for B++(High) utilities and pipelines and EPGI is rated B++ (Mid). Ms. McLeod had stated that there was a substantial difference in rating quality between a B++ (High) and a B++ (Mid). EPTI submitted that there was no basis on which to conclude that EPTI's bond rating would be as high as EPGI's BBB (Mid). EPTI's smaller equity base, lower coverage ratios and lower common equity ratios would make it riskier. Ms. McLeod had stated that it would be expensive and difficult for EPTI to issue debt. EPTI concluded that its required debt cost spread would be no less than that of EPGI.

EPTI noted that ENMAX did not dispute the reasonableness of the 7.3% cost rate in light of capital market prospects at the time the EPTI forecast was prepared. EPTI considered ENMAX was attempting to improperly update EPTI's forecast. EPTI submitted that the Board should reject ENMAX's argument and proposals respecting EPTI's cost of debt.

Position of ENMAX

ENMAX noted that in the 1996 GTA proceedings, TransAlta forecast a long-term debt issue but went ahead with a short-term issue. ENMAX submitted that TransAlta has been benefiting from a term differential for two years or more. Therefore, ENMAX did not believe that TransAlta should receive a premium related to the proposed long term debt issues when its was likely that 10-year debt was likely all that would be issued.

ENMAX further noted that TransAlta forecast debt costs which were more typical of an A (low) to BBB (high), despite its AA rating, ENMAX calculated that TransAlta was requesting a premium for 1999 of 115 basis points over long Canada bonds and 140 basis points for 2000. ENMAX considered that this was in the same range as the premium EPGI/EPTI were forecasting for a BBB rated. ENMAX noted that two TransAlta issues were trading at only 52 and 70 basis points over equivalent long Canada issues. ENMAX recommended that the Board approve for

TransAlta a debt cost of 50-60 basis point spread for both long term issues, which resulted in a debt rate of 5.50% to 5.60%.

ENMAX noted that EPTI's application used a cost rate of 7.3% for its $45 million 1999 debt issue. ENMAX considered that this rate included a 40 basis point spread between long-term and short term Government of Canada bonds. Furthermore, this spread was overstated by 26 basis points since the yield between long term and short term Government of Canada bonds as of May 1999 was only 14 basis points. ENMAX noted that Dr. Evans had estimated a spread of 25 basis points between Government of Canada bonds with a 10-year yield, and those with a maturity of greater than 10 years. EPTI also used a 130 basis point adjustment for "corporate spread and fees" composed of 120 basis points for the spread from BBB, and 10 basis points in fees. ENMAX noted that Drs. Waters and Winter indicated that a BBB bond, assuming the new issue is rated that low, would have a spread over long Canada's of less than 120 basis points. This was confirmed by Dr. Evans. ENMAX concluded that based on these spreads, EPTI's new 1999 debt should have a cost rate of approximately 6.45% if the debt was issued as scheduled. If, by the time of refiling EPTI has not issued the debt, ENMAX considered that the new debt should bear a banker acceptance rate of approximately 4.0% – 5.0%.

ENMAX considered that EPGI and EPTI did not use actual forecast capital structure in their applications. ENMAX considered that the capital ratios were different from the supporting data because EPGI and EPTI only included long-term debt and the shareholder's equity in the capital structure calculation. However the forecast balance sheets included short-term debt such as bank indebtedness. Therefore they are proposing neither a forecast actual capital structure nor an actual forecast capital structure. ENMAX noted the Dr. Bridgeman stated short-term debt should not be included because the balances were not significant and they were part of normal business. ENMAX considered that the real reason EPGI and EPTI wished to exclude short-term debt is that returns would be increased if actual debt with a cost of 4 - 5% were treated as though it had a cost rate equivalent to the composite rate of return. ENMAX submitted that the concept of cost of service required that EPGI and EPTI not mark up their short-term debt costs by 100% by treating them as long-term debt and equity.

ENMAX submitted that the capital structure for EPGI and EPTI should be as outlined in Exhibits 31, 32, 33 and as recalculated from Exhibit 37. The debt component should be segregated between short-term and long-term debt. ENMAX concluded the cost of the short-term debt should be equivalent to bankers' acceptance rates.

In reply argument, ENMAX stated that EPGI and EPTI were incorrect in argument. ENMAX did question the appropriateness of the new debt costs at the hearing, as well as suggesting that the short-term debt should be factored into the calculation of the embedded cost of debt.

Position of the FIRM Customers

The FIRM Customers submitted that the Board should use a rate of 6.2% on TransAlta's new debt issues in 1999-2000. The FIRM Customers considered that this would be consistent with a

5.5% Long Canada rate and a spread of 70 basis points for TransAlta debt. The FIRM Customers noted that Drs. Waters and Winter had calculated the debt spreads for both intermediate and long-term debt for electric utilities and TransAlta's debt was higher quality than the industry. However, in reply the FIRM Customers agreed with the argument of ENMAX regarding TransAlta's cost of debt and preferred stock issued in 1999-2000.

The FIRM Customers also agreed with ENMAX concerning the cost of debt associated with EPTI's new $45 million debt issue. The FIRM Customers considered that EPTI overstated the cost of 10-year debt and the spread between 10-year and 30-year debt. The FIRM Customers calculated that this would result in a difference of 85 basis points or $383,000 in revenue requirement.

The FIRM Customers agreed with ENMAX's position on the treatment of short-term debt. The FIRM Customers noted ENMAX's analysis of the balance sheets of EPGI and EPTI in Exhibits 31, 32, 33 and 37 and concluded that the debt-equity ratios applied for by EPGI and EPTI are correct only if short-term debt were included as part of the debt rate. The FIRM Customers submitted that EPGI was issuing short-term debt but receiving revenue as if it were more expensive, long-term debt.

Board Findings

Having determined the proportion of debt to be included in each utility's capital structure in the section on business risk, the Board will now determine the cost rate of debt for each test year for each utility. The issues raised with respect to the cost of debt are the inclusion of short-term debt in the capital structure and the forecast rates of new issues.

The Board's practice has been to include the cost of short-term debt in the embedded cost of debt when the prudent financial policies of the utility result in short-term debt becoming a permanent feature of the utility's capital structure. The Board sets rates that may be in place for an extended period and, therefore, the revenue requirement should reflect the long-term cost of capital only. If short-term debt is a significant and permanent feature of corporate financing, this cost to the company should be recovered in the rates charged to customers. If short-term debt were not a permanent feature of a company's capital structure, it would not be reasonable to include the cost of short-term debt in the embedded cost of debt. The evidence of EPGI/EPTI's financial witnesses is that the current short-term debt has been incurred in anticipation of a long-term issue. The Board accepts that the financial policy of EPGI/EPTI's management is to not incur significant amounts of short-term debt on a long-term basis. There has been no suggestion that EPGI/EPTI's financial policies are imprudent as to the amount financed, in incurring the bridge financing or with respect to the timing of the long-term issue. The Board accepts EPGI/EPTI's cost of debt excluding the current short-term financing. The Board accepts TransAlta's cost of debt including short-term financing as that company's financial policy leads to significant amounts of short-term debt as a permanent feature of the company's financial structure. As noted in the section dealing with customer deposits, the Board considers that these

deposits are treated as liabilities and, although short-term in nature, are an on-going feature of TransAlta's capital structure.

With respect to the forecast cost of new issues, the Board accepts the cost rates as filed by TransAlta and EPGI/EPTI. The Board evaluated the arguments of ENMAX and the utilities and considers that the rates forecast by the utilities better account for the transaction costs of new issues, the credit rating of the individual companies and the risks of market volatility. Accordingly, the Board is not persuaded that it should replace the Utilities' forecasted rates with the rates forecast by ENMAX.

Therefore, the Board directs TransAlta to refile its embedded cost of debt for 1999 and 2000 incorporating the mid-year forecast amount of customer deposits. For EPGI, the Board approves a mid-year forecast embedded cost of debt of 10.22% for 1999 and 10.19% for 2000. The Board approves EPTI's forecast of mid year embedded cost of debt to be 10.08% for 1999 and 9.44% for 2000.

(2) Cost of Preferred Shares

The mid-year cost of preferred shares consists of the cost of prudently incurred embedded cost plus new preferred issues at the rate they are forecast to be issued.

TransAlta forecast an issue of $145.3 million of preferred shares in the year 2000 at a rate of 6%. This issue was intended to replace the 8.4% preferred shares that TransAlta expects to retire in the year 2000.

Position of TransAlta

TransAlta disagreed with ENMAX's recommendation of 4.85% for its new preferred share issue. TransAlta noted that ENMAX's position was based solely on Mr. Falconer's evidence provided in May 1999. TransAlta submitted that its process of determining the forecast preferred dividend rate was similar to its process of determining forecast interest rates. These forecasts were primarily based on advice from investment dealers familiar with TransAlta's situation. TransAlta submitted that ENMAX's selective use of subsequent information, was inappropriate and unfair. TransAlta submitted that its proposed preferred share cost was reasonable.

Position of ENMAX

ENMAX, noted in argument that TransAlta's witness, Mr. Falconer, had considered that the forecast 6% dividend appeared to be very generous and that the preferred share should have a yield of approximately 90% of 5.37%, or approximately 4.85%.[414] ENMAX submitted that the proposed preferred share issue should have a rate of at least 100 basis points less than that proposed by TransAlta, or 4.85%.

[414] Tr. p.4897, l.3-5

Position of the FIRM Customers

The FIRM Customers submitted that TransAlta overstated the cost of preferred shares. The FIRM Customers agreed with the argument of ENMAX on this issue.

Board Findings

The only issue raised with respect to preferred shares is the cost rate of the proposed offering of TransAlta preferred shares in the year 2000. No issue was raised as to whether it was prudent to replace one issue of preferred shares with another issue.

Concerning the cost of the proposed issue, the Board agrees that the 6% rate may have been the best estimate of the rate of a new preferred issue at the time TransAlta's Application was prepared. However, it was TransAlta's witness, Mr. Falconer, who provided an updated estimate of the cost of a new preferred issue at the time of the hearing. The Board's practice has been to accept updates provided at the time of the hearing as the most current and best information upon which to base its decision. Therefore, the Board accepts TransAlta's witness' estimation method of 90% of the risk-free rate as the most current forecast of the cost of a preferred share issue. The Board further notes that TransAlta, in reply, did not dispute the validity of its witness' method nor did TransAlta provide any further support to its original forecast rate of 6%.

The Board notes that the 4.85% rate proposed by ENMAX is based on a risk-free rate in the range of 5.25-5.37%. In the section on equity risk premium, the Board sets out its reasons why a prospective risk-free rate of 5.75% is preferable for the purposes of these proceedings. Accordingly, the Board estimates that a rate of 5.25% (i.e., 5.25%/5.75% = 91%) is the best estimate of the cost rate of the proposed preferred share issue. This rate accounts for a certain amount of forecast risk, is in accord with the testimony of TransAlta's financial markets witness and is consistent with the Board's findings on risk-free rate.

The Board directs TransAlta to incorporate a dividend rate of 5.25% for its proposed preferred share issue in its refiling of revenue requirement.

(3) After Tax Weighted Average Cost of Capital

TransAlta proposed that the after tax weighted average cost of capital (ATWACC) model be used to determine the fair return component of TransAlta's revenue requirement on an integrated basis and by line of business.

The ATWACC model sets the rate of a return for a firm, or line of business within the firm, by focusing on the overall after-tax cost of capital. The overall after-tax cost of capital of a line of business is assumed to be constant over a broad middle range of capital structures, because any net tax advantage to the use of debt is offset by other costs. The overall rate of return for a firm, or line of business within the firm, is determined by averaging the overall after-tax cost of capital

of a sample of publicly traded firms in that line of business, if such a sample is available. This was the approach used by TransAlta's cost of capital witnesses Dr. Kolbe and Dr. Vilbert in estimating the cost of capital for the integrated utility and for each of TransAlta's electric lines of business.

The ATWACC model is designed to measure the after tax weighted average cost of capital for a firm which is assumed to be appropriate over a broad range of capital structures.

Issues raised during the proceedings included the following:

- Why Change?
- Is a Capital Structure Still Required?
- Communication of ATWACC
- Merits of ATWACC

The Board will deal with each of these issues below.

(A) Why Change?

Position of TransAlta

Dr. Kolbe, in his evidence-in-chief, testified that ATWACC was more than "just another system of measurement that has been developed to measure the fair return on rate base."[415] He identified three potential advantages to using ATWACC:

- an assured consistency between the cost of equity and the share of equity - the more debt a company has, the more financial risk the equity bears and the higher the cost of equity;
- using ATWACC, particularly in the context of going to a line of business cost of capital, simplifies our lives[416] - under the current system the Board has two hard things to do: estimate the cost of equity and estimate a capital structure; while if the Board adopts ATWACC it has only one of the hard things to do, namely get the ATWACC right; and
- with deregulation, ATWACC is the term under which new, deregulated businesses are going to be thinking - it will facilitate communications between what the Board does and what the rest of industry is doing.[417]

Mr. Wilson, of the Board staff, asked Dr. Kolbe about the wisdom of adopting ATWACC when generation will be deregulated in 2001. Dr. Kolbe responded:

[415] Tr. p.4941
[416] Tr. p.4944
[417] Tr. p.4946

> I think that is one of the strongest reasons to try to adopt it. The vast majority of TransAlta, you know, 58 percent by the measure I have, is generation assets, and if those assets become subject to PPA risk provisions and PPA return, the Board is going to have to try to decide what the return should be on the transmission and distribution assets which remain behind. But at least with respect to companies that remain integrated and just deregulate while still owning the assets so that the share price you look at and the share variability you look at reflects not only the transmission and distribution but also the generation. It is going to be difficult to try to decide on line of business, cost of capital... My view is that it is easier to draw inferences about one hard thing than about two hard things, that the after-tax weighted average cost of capital lets you put aside a focus on capital structure independently of cost of equity.[418]

TransAlta submitted that the ATWACC method is nothing more than the natural evolution of regulatory practice in line with ongoing developments in financial theory. Of course, if regulatory precedent were the sole criteria, there would never be progress in regulation. More fundamentally, the use of ATWACC is, in fact, being accepted by regulators. As noted by Dr. Kolbe, it is already in use in the United Kingdom. Moreover, the use of ATWACC would increase the understanding between regulated and non-regulated businesses since both would be using the same language which will become increasingly important as a greater portion of the electric utility industry is subject to competition.[419]

Position of COCI

The COCI noted the position of Mr. Waiand and Mr. Way that ATWACC gives management more flexibility, apparently because it allows management to set the equity component of the capital structure within a broad range, without Board review. That may be useful for management, but it does not protect the interests of the ratepayers. Decisions on actual capital structure have always been the preserve of utility management. The question of whether the costs of the capital structure chosen by management may then be recovered from ratepayers has been and remains the preserve of the regulator.[420] Imposition of ATWACC does not provide any justification for a request that the Board abdicate its regulatory responsibility. It seems to the COCI that this reason advanced by TransAlta for acceptance of ATWACC should be seen for what it is — another attempt to take the control of the capital structure issue away from the Board — and be rejected.

The COCI submitted the following:

> It is significant to note that there is no regulatory precedent for the utilization of ATWACC. Drs. Kolbe and Vilbert admitted as much in their response to a Board

[418] Tr. p.5133
[419] TransAlta Reply Argument, p.76-77
[420] Tr. p.4203

information request (Exhibit 15, BR.TAU-42). By the time of their appearance on the witness stand, Dr. Kolbe and his colleagues at Brattle had beaten the bushes vigorously enough to flush out one utilization of *pre-tax* WACC in the United Kingdom (T4936). The exception proves the rule. The fact that only one instance of any similarity can be pointed to (and that instance can only be described as a "stretch") confirms the absence of regulatory acceptance of ATWACC.[421]

The timing of the TransAlta proposal to switch to the ATWACC methodology is perverse and cannot be justified by vague references to "how business thinks" and "preparing to go to line of business cost of capital". The EUB has regulated TransAlta and the other Alberta electric utilities for many years, using the capital structure/rate of return approach. The 1998 amendments to the EUA have established a new regime starting in 2001 which is intended to involve PPAs that remove generation from rate of return regulation. It is more than puzzling that TransAlta would choose the last decision of the EUB under the old regime to initiate a fundamental change in approach to the cost of capital issue. The regime of the EUB in regulating utility cost of capital is not over and will not be over until 2001. The dubious argument that ATWACC can simplify line of business return regulation in the post-2000 era is no justification for adopting ATWACC now. The Cost of Capital Intervenors submit that, even if ATWACC were meritorious (which it isn't), the timing proposed by TransAlta for its implementation is not.[422]

Board Findings

The Board notes that the advocates of ATWACC claim there are considerable advantages to using ATWACC in the regulatory process. These potential advantages are listed below:

- Enables the determination of a fair return without making specific determinations for capital structure and rate of return on equity.
- The previous advantage provides further benefits when fair return must be established for each of the Generation, Transmission and Distribution business functions.
- The competitive market uses ATWACC for evaluating business ventures. As the electric industry restructures and deregulates and regulated firms interact with deregulated firms, the cost of capital will be described in common terms.

The Board notes that another claimed advantage of ATWACC is that it provides utility management with the flexibility of adjusting capital structure. However, the Board notes that this flexibility is also available within the traditional approach.

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[421] COCI Argument, p.13
[422] COCI Argument, p.20-21

The Board considers that ATWACC merits consideration in these proceedings in view of the potential advantages to the regulatory process.

The Board is not persuaded by the argument of the COCI that, even if ATWACC were meritorious, the timing is such that it should not be implemented for the 1999 and 2000 proceeding. The Board agrees that there is no particular urgency that ATWACC be adopted for this particular proceeding. However, if the ATWACC method has merit in determining a fair return, the Board could adopt it for the 1999/2000 test years.

(B) Is a Capital Structure Still Required?

Position of TransAlta

The Board questioned whether, under ATWACC, it was still necessary to deem a capital structure in order to make adjustments for the embedded costs of debt and preferred shares and to calculate the income tax component of the revenue requirement.[423]

Dr. Kolbe agreed that it was necessary to know the actual amount of debt in order to "make sure you have the right size cheque" in order to be able to pay the actual interest expense. In order to calculate the actual equity taxes, which the Board now does, requires some tax wizardry because the average taxes paid are not equivalent to the marginal tax rate. This is due to tax timing differences from depreciation and other factors.

TransAlta stated:

> CCI asserts that Drs. Kolbe and Vilbert maintain that capital structure is irrelevant. CCI has misconstrued Drs. Kolbe and Vilbert's testimony. Drs. Kolbe and Vilbert's position on capital structure is with regard to the ATWACC. Within the broad middle range of capital structures, the ATWACC is constant. Even within the ATWACC methodology, capital structure is important because the return on equity is a function of the capital structure. As more debt is added to the capital structure, the return on equity must increase in order to compensate for the increased financial risk associated with more financial leverage. It is only in that context that Drs. Kolbe and Vilbert have argued that capital structure is irrelevant. As Dr. Kolbe said in his testimony, bond holders and rating agencies are concerned with capital structure.[424]

Position of COCI

The Chairman and Dr. Kolbe had an enlightening discussion of the failure of ATWACC to eliminate the necessity for the regulator to determine a common equity ratio and a rate of

[423] Tr. p.5174
[424] TransAlta Reply Argument, p.83

return.[425] The COCI submitted that it is clear from this discussion that ATWACC is, in fact, just another system of measurement. Adoption of this new system would do much more to confuse the fair return debate than to clarify it.

The COCI stated that it seemed arrogant of Dr. Kolbe to suggest that "we" have learned that a "focus on capital structure is no longer needed,"[426] when the importance of capital structure is the very issue that he has brought to the EUB for determination. The COCI have *not* learned that it is unnecessary to focus on capital structure, and respectfully submit that the focus is not only necessary but desirable and appropriate.

Board Findings

The Board considers that capital structure is important from the perspective of determining adjustments for the embedded costs of debt and preferred shares and to calculate the income tax component of the revenue requirement.

The Board further considers that capital structure is important for equity investors to be able to understand the allowed equity rate of return. Capital structure is also necessary to enable the calculation of coverage ratios and other financial indicators that are important to bond holders and credit rating agencies.

The Board notes that section 52(1) of the EU Act requires the Board to "provide the owner of an electric utility with a reasonable opportunity to recover the costs associated with capital related to the owner's investment in the electric utility… if the costs are prudent and if, in the Board's opinion, they provide an appropriate composition of debt and equity for the investment."

The Board notes that the traditional method explicitly determines the appropriate composition of debt and equity. However, the Board considers that the legislative requirement of "an appropriate composition of debt and equity" can also be satisfied by selecting an appropriate ATWACC that supports appropriate combinations of debt and equity.

The Board considers that whatever method is used, the focus should be on determining a fair return and not necessarily on the tools used to arrive at the fair return.

(C) Communication of After Tax Weighted Average Cost of Capital

Position of TransAlta

Dr. Kolbe recommended that it might be useful for the Board to initially report the results using both systems during a transitional period before converting solely to ATWACC.[427]

[425] Tr. p.5171-5175
[426] Tr. p.4946
[427] Tr. p.5190

Position of COCI

The COCI submitted that ATWACC could potentially create communication confusion. Whatever the protestations and assurances of the TransAlta witness team, ATWACC is confusing.

Dr. Winter put it best when he stated in response to a question from the Chairman:

> If I could step back also and contrast the ATWACC approach with the traditional approach just in terms of the language, because when you come up with a decision, you can express it one of two ways. Suppose that you accepted Drs. Kolbe and Vilbert's recommendation of 6.91 percent as the ATWACC, you can make that announcement as a decision, or you could state the decision is 11.2 percent on 40 percent of equity.
>
> You have to think about which is the clearest way to communicate that decision to investors and to ratepayers. It is clear that if you communicated it in the standard way, that we have kept the equity ratio the same as last year, in fact, we have kept the award, 11.2 percent, about the same as last year, people would know what that meant. You would hear gasps of dismay from intervenors and expressions of satisfaction from companies.
>
> If you announced 6.91 percent, what you would do is send investors back to their computers to try and untangle the implied return on book equity from that 6.9 percent, because what investors in equity are going to be interested in is income available to equity. The income available to equity is given by the fair rate of return.
>
> That would be the bottom line to investors. You could either provide that to them directly by communicating a return of 11.25 percent, or you could announce the ATWACC and have them try and go through the calculations themselves. They would have to go through the adjustments that Drs. Kolbe and Vilbert did for the difference between embedded and market costs of debt and preferred. Investors would have to know which cost of preferred you had in mind in making that investment and so on.[428]

Dr. Kolbe acknowledged that there are no methods by which ATWACC can be tracked in the marketplace — it must be inferred.[429] Mr. Falconer confirmed that the bond rating agencies do

[428] Tr. p.5283-5284
[429] Tr. p.4958

not report ATWACC, but they do report the equity component of the capital structure and the return on that equity.[430]

The COCI submitted that it is imperative that the Board minimize confusion in this period of regulatory change by retaining the traditional cost of capital methodology and the clarity of its communication.

Board Findings

The Board considers that to the extent it uses the ATWACC concept, it is extremely important to communicate the results of the determination of the fair return using both the traditional and ATWACC methods so that all parties clearly understand the numerical relationships between the two methods.

(D) Merits of After Tax Weighted Average Cost of Capital

Position of TransAlta

Are the ATWACC and Composite Cost of Capital Methods Mathematically Equivalent; and, if so, do we have a Distinction Without a Difference?

The Chairman posed the above question to Dr. Kolbe at T5169. Dr. Kolbe agreed that the methods were equivalent, but only if you keep track of the market capitalization. He said further at Tr. p.5171: "The only thing that makes the market to book ratio have any claim to evidence on return is the existence of book value rate bases."

TransAlta submitted that it is clear from the exchange between the Chairman and Dr. Kolbe at Tr. p.5173ff, that the past practice of obtaining a cost of equity estimate and applying it directly to the book equity capital structure is incorrect. The cost of equity is determined in the market, not from book value. When applied to a book value capital structure the cost of equity must be adjusted for differences in financial leverage between the market value and book value capital structures.

Position of COCI

COCI stated the following:

> The adjustment for leverage is important for ATWACCers because, in their world, any decrease in the equity ratio must be met by a large increase in ROE. The ATWACC is constant — to offset the extra tax-shield benefits of debt, ATWACCers need to assume a large increase in the hidden costs of equity. The ATWACC method magnifies the increase in ROE that is necessary to offset any increase in leverage. It is one more way for the TAU experts to increase their

[430] Tr. p.4896

> recommendation. The adjustment made by Drs. Kolbe and Vilbert exacerbates the unfairness in a recommendation that is already too high. The bottom line of the Brattle evidence is a ROE of 11.2 percent at 40 percent equity — only 5 basis points lower than the award given by the Board in the 1996 case when interest rates were 200 basis point higher. Yet TransAlta brings no evidence whatsoever that TAU investors have been struggling with an inadequate return, and the company market-to-book ratio remains greater than 2 (Exhibit 162-Table 12). It is perverse that under the ATWACC approach, higher values in the market will make the adjustment greater, i.e. the better the firm does in the market, the more the ATWACCers would adjust their award upwards — a reverse death spiral."[431]

Position of LE/RD

LE/RD submitted that the ATWACC method appears to be one that is appropriate for unregulated industry. In fact, in a response related to the issue of adjusting for embedded debt, TransAlta's expert may have betrayed the non-regulated application of the model when he stated that "TransAlta like every other unregulated company, is at risk for unanticipated changes in interest rates, and you go to a pure market standard."[432] However, TransAlta is not an unregulated company for the purpose of this application and there are aspects of the model that do not fit the regulated model currently in place.

The model is a market-based model, which requires at the very least adjustment for embedded cost of debt and in that connection regard to capital structure. As such it represents, when applied in the current situation, a hybrid of market and embedded calculations which may reduce its value as a market based method.

Position of the FIRM Customers

The FIRM Customers summarized their position as follows:

> While superficially appealing from the perspective of economic theory, the ATWACC theory does not fit the reality of the Canadian regulated utility industry. The flat ATWACC over a broad range does not exist according to Dr. Vilbert's data. The changes in the return on equity and the beta measures of stock price risk that would be mathematically required for small changes in capital structure if ATWACC were correct lack credibility in the Utility industry. The ATWACC method also improperly sweeps risky, but potentially highly profitable unregulated activities, into the utility cost of capital and leads in the direction of an illegal fair value rate base. Finally, contrary to Dr. Kolbe's confused statements, ATWACC cannot be used to compute a return on book value equity in the manner he proposes unless TAU also expects the Board to believe there will be a sudden, sharp drop in TransAlta Corporation's stock price as a result of TAU

[431] COCI Argument, p.17-18
[432] LE/RD Argument, p.11

getting everything it has applied for. Therefore, in conclusion, the Board should not adopt ATWACC for purposes of utility regulation.[433]

In sum, if the Board is to believe Dr. Kolbe's statement, TransAlta Utilities, mathematically would require an increased return of 120-146 basis points on common equity at a 42% equity percentage. The beta for TransAlta Utilities would increase from 0.63 (after Dr. Vilbert's adjustments) to between 0.95 and 0.99. Most importantly, it must be noted this calculation contains no judgement or financial analysis. It is the inevitable and mechanical result of Dr. Kolbe's ATWACC theory using Dr. Vilbert's numbers on TransAlta Corporation's cost of capital and is entirely consistent with Dr. Kolbe's comments during the hearing. [T5163] Consequently, we submit the Board need not take Dr. Kolbe's word for it or Dr. Waters' word against it. The credibility of Dr. Kolbe's statement may be tested by comparing its arithmetic implications to Dr. Vilbert's sample of Canadian utilities (as shown in Figure 1 and previously discussed).[434]

Board Findings

The Board is required by statute to:

> …provide the owner of an electric utility with a reasonable opportunity to recover the costs associated with capital related to the owner's investment in the electric utility, including
>
> (i) depreciation
>
> (ii) interest paid on money borrowed for the purpose of the investment
>
> (iii) any return required to be paid to preferred shareholders of the electric utility relating to the investment
>
> (iv) a fair return on the equity of shareholders of the electric utility as it relates to the investment, and
>
> (v) taxes associated with the investment,
>
> if the costs are prudent and if, in the Board's opinion, they provide an appropriate composition of debt and equity for the investment.[435]

[433] FIRM Customers Argument, p.40
[434] FIRM Customers Argument, p.31-32
[435] EU Act, section 52(1)

It is extremely important to recognize that any model or method adopted by the Board to determine fair return must ensure that the total fair return is limited to a return based on the costs associated with the owner's capital investment (i.e. original book cost) not the market value of the assets. In other words, the true value of a pure play regulated entity is represented by book value, not what the market value may be from time to time. The Board, in meeting the fair return standard, must ensure that the allowed fair return is equal to the return earned by other firms of comparable risk and is sufficient to attract the necessary capital to provide reliable service.

The Board notes that the market capitalization of a utility can be influenced by unregulated activities and also

> ...a variety of rational and irrational forces in the capital markets. The psychology of market depressions and euphoria or institutional constraints may carry share prices away from their intrinsic long-run values.[436]

The Board observes that the intrinsic long-run value of a pure play regulated entity is best represented by book value. In other words, the present worth of future regulated earnings, discounted at the allowed return, is by definition equal to book value assuming achieved regulated earnings on average equal allowed regulated earnings. Accordingly, the Board considers that book capitalization represents the best indicator of the long-run market capitalization for a pure play regulated firm.

The Board considers that the above statutory requirement and discussion do not necessarily invalidate the ATWACC model since the ATWACC, although developed from weighted market capitalization ratios, is in fact applied to the book value of the assets. To evaluate the ATWACC model, the Board considers that it must resolve the following two critical issues:

- Does the ATWACC remain constant regardless of whether it is derived from market capitalization ratios or book capitalization ratios?
- If not, do weighted market capitalization ratios or weighted book capitalization ratios provide an ATWACC that meets the fair return standard?

The Board notes the common ground between TransAlta and the Intervenors is that the cost of equity can be determined from market data using tests such as the DCF test and risk premium or risk positioning tests. The market data includes market risk premiums and betas derived from the underlying equity market capitalizations. There would be no debate as to the appropriate ATWACC if market capitalization ratios were equal to book capitalization ratios.

When the market equity capitalization ratio is greater than (less than) the book equity capitalization ratio, Drs. Kolbe and Vilbert assume that beta and equity rate of return must be

[436] Dr. Evans Evidence A-14, A-15

increased (or decreased) if applied to the book equity in order to preserve the theory that ATWACC remains constant over a broad range of capitalization ratios.

The Intervenors on the other hand assume that beta and equity rate of return measured using market data must stay constant when applied to book equity. Of necessity, under the Intervenor's assumption, the ATWACC must increase (decrease) as the equity ratio increases (decreases). The FIRM Customers demonstrated that ATWACC did in fact increase as the market equity ratio increased for the firms contained in Dr. Vilbert's sample Canadian utilities.

The Board agrees with Drs. Kolbe and Vilbert that beta and the cost of equity generally increase (decrease) as the equity market capitalization decreases (increases) for unregulated firms. It is important to note that the earnings of an unregulated firm are "governed" by the competitive market and have unlimited upside potential and downside risk. On the other hand, the earnings of a regulated firm have a more limited upside potential and downside risk. In essence, a regulated company's earnings are driven by the portion of the original cost rate base deemed to be financed by common equity. This fact results in a fundamental disconnect to the theory that market capitalization ratios, which have deviated significantly from book capitalization ratios, reflect the appropriate financial risk necessary to determine a fair composite return to be applied to the original cost rate base of a pure play regulated utility. This is because the earnings of a pure play regulated utility are governed by and driven by the regulated return allowed on book equity. In other words, it is the book equity that reflects the appropriate financial risk necessary to determine a fair composite return for a pure play regulated utility.

Accordingly, the Board considers that beta and the cost of equity do not change to the extent necessary for an ATWACC, determined from market capitalization weights, to remain constant when applied to the book capitalization for a pure play regulated utility. The increase required to the cost of equity to achieve a constant ATWACC would be excessive and violate the fair return standard.

The Board disagrees with TransAlta that

> ...the past practice of obtaining a cost of equity estimate and applying it directly to the book equity capital structure is incorrect. The cost of equity is determined in the market, not from book. When applied to a book value capital structure the cost of equity must be adjusted for differences in financial leverage between the market value and book value capital structures.[437]

The Board considers that the fair return standard is met when a utility is given the opportunity to earn a market equity rate of return on a book equity that has been set at a level consistent with the business risks of the firm. The Board agrees with the conclusions of the FIRM Customers that

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[437] TransAlta Argument, p.57

> ...the changes in the return on equity and the beta measures of stock price risk that would be mathematically required for small changes in capital structure if ATWACC were correct lack credibility in the Utility industry.[438]

The Board notes that traditional regulatory practice has assumed that the beta and cost of equity measured using market data from firms of equivalent risk is directly applicable to the portion of the original cost rate base deemed to be financed by equity capital. The Board also notes that the allowed market cost of equity includes inflationary expectations which appropriately compensates the owner of an original cost rate base for the cost of inflation. The objective of traditional regulatory practice is to ensure that the portion of the original cost rate base that is deemed to be financed by equity capital is set at a level consistent with the business risks of the firm. The Board is not persuaded that it should deviate from this longstanding past practice that meets the fairness test set out in the legislation.

Further, the Board can not turn a blind eye to the empirical data from Dr. Vilbert's Canadian and U.S. sample companies which clearly show that the ATWACC increases as the market equity ratio increases over the broad 30%-65% range used by Dr. Vilbert to calculate an average ATWACC which was then deemed to be the constant ATWACC over this range. The Board notes that a modified ATWACC calculated from the same samples but using weighted book capitalization ratios also increases over a broad 25%-54% range but remains relatively constant over a narrow middle range of 35-45% of book equity for the Canadian companies and 40-45% for the US companies.[439]

The Board considers that beta and the cost of equity would generally increase (decrease) as the book equity capitalization decreases (increases) for regulated firms. In other words, the Board considers that an ATWACC developed from weighted book capitalization would remain constant over a narrow middle range of book capitalization ratios regardless of market equity capitalization. It follows that beta and cost of equity would also remain fairly constant, provided the equity book ratio remains constant, regardless of the market equity capitalization ratio.

The Board agrees that an ATWACC determined from market capitalization ratios appropriately measures the true ATWACC for an unregulated firm given current market prices, market value and beta for that firm. The Board considers that there is a correlation between market equity capitalization ratios and the value that investors place on the firm. For, example, the Board notes that investors do anticipate potential future earnings, the present worth of which is far in excess of the book capitalization of the firm. This investor expectation would manifest itself in a common equity market to book ratio that significantly exceeds the debt market to book ratio.

[438] FIRM Customers Argument, p.40
[439] See Appendix 1

It follows that the fair return must be developed from book capitalization ratios since a fair return based on market capitalization ratios would be excessive. Further, the Board considers that an ATWACC determined using book capitalization ratios appropriately measures the true ATWACC for a regulated firm.

The Board would be derelict in its statutory responsibilities to recognize market capitalization ratios that are derived from a market value capitalization that deviates from the intrinsic long-run value of the regulated firm. For example, if the Board has traditionally set an allowed equity return based on book equity and this has resulted in a equity market capitalization which is considerably above a ratio of one, an ATWACC based on market capitalization ratios would call for a higher composite return. Circularity could then develop in the process. To the extent that the higher return was granted, the equity market capitalization would in all probability rise even further which, if it went outside the narrow middle range, would again call for a higher ATWACC. The Board must ensure that this potential circularity is avoided.

For all of the above reasons, the Board rejects the concept that an ATWACC determined using market capitalization ratios of sample regulated firms is directly transferable to the book assets of a regulated firm when the common equity market to book ratio significantly exceeds the debt market to book ratio. In these situations, the direct transfer of an ATWACC weighted with market capitalization results in a higher return than a return determined using book capitalization weightings. The danger is that the higher ATWACC return does not meet the regulatory and legislative test of fairness.

Accordingly, the Board finds it necessary to reject TransAlta's version of the ATWACC model which proposes the use of market capitalization ratios. Accordingly, the Board considers that it should place primary weight on the traditional method in the development of a fair return for these proceedings.

Nevertheless, the Board considers that useful insights and assistance can be obtained from the principles of the ATWACC concept that will assist it in determining the fair return for the integrated company as well as by business function. However, the Board considers that if the ATWACC model is to provide any assistance, a ***fair*** ATWACC must be determined using weighted book capitalization ratios rather than weighted market capitalization ratios. The Board, hereinafter, will use the acronym $ATWACC_{MV}$ to refer to an ATWACC determined using weighted market value capitalization ratios and the acronym $ATWACC_{BV}$ to refer to an ATWACC determined using weighted book value capitalization ratios. An $ATWACC_{BV}$ would be suitable for a regulated utility whose profit, by legislation, is limited to a fair return on the book value (i.e. original cost) of its assets. The Board notes that an $ATWACC_{BV}$ is consistent with the logic of the traditional method of determining fair return.

Accordingly, the Board will use both the traditional method and an $ATWACC_{BV}$ as tools to arrive at the fair return for EPGI/EPTI and TransAlta with primary weight placed on the

traditional method. The Board notes that since EPGI and EPTI do not pay income tax, the $ATWACC_{BV}$ model collapses to the traditional method used to determine the fair return.

The Board, in arriving at a fair return using the traditional method, has used the following steps:

- Determine a range of acceptable book capital structure ratios consistent with the business risks of the integrated company.
- Determine a range of acceptable equity rate of returns using standard tests.
- Determine the fair return using the mid-point estimate from the capital structure and equity rate of return ranges.
- Determine a range of acceptable book capital structure ratios consistent with the business risks of GENCO, TRANSCO and DISCO.
- Utilize the integrated company range of acceptable equity rate of returns for GENCO, TRANSCO and DISCO.
- Determine the fair return for GENCO, TRANSCO and DISCO using the mid-point estimate from the capital structure and equity rate of return ranges.
- Determine the book income tax associated with the preferred and common equity components of the capital structure.
- Determine the income tax adjustments to be added to the book income tax.

The Board, in arriving at the fair return and income tax using the $ATWACC_{BV}$ method, will use the following steps:

- Determine an ATWACC, appropriate for the integrated company, from Dr. Vilbert's sample Canadian and U.S. companies using book rather than market capitalization weightings.
- Determine an appropriate adjustment to the above ATWACC to eliminate any distortion caused by involvement in unregulated activities.
- Determine an appropriate adjustment to ATWACC consistent with Board approved market equity rate of returns.
- Determine differentials to the integrated ATWACC to determine an ATWACC appropriate for GENCO, TRANSCO and DISCO.
- Adjust the ATWACCs for differences between the embedded and current cost rates of debt and preferred.
- Gross up the adjusted ATWACC return by dividing by one minus the tax rate to arrive at the allowed fair return plus the book income tax.
- Determine the income tax adjustments to be added to the book income tax.

The Board considers that expressing the fair return under the traditional and $ATWACC_{BV}$ methods has advantages. The $ATWACC_{BV}$ will be useful to the Board in examining Dr. Kolbe's evidence respecting the change in ATWACC by business function. However, the Board disagrees with the basic principle of the ATWACC model that the after-tax composite cost of capital is relatively constant over a broad middle range of capital structures. The Board considers

that the basic ATWACC principle holds true using book capitalization ratios over a narrow range. Recognition that the cost of capital is constant over a narrow range has the following attractive and desirable features from a regulatory perspective:

- Similar to the traditional method, the Board considers that utility management retains the flexibility to determine actual capital structure within a prudent narrow range.
- The Board considers the $ATWACC_{BV}$ model to be useful in demonstrating the relationship between common equity ratio and equity rate of return over the narrow range that is consistent with the allowed fair return and income tax.

The Board considers it extremely important to reconcile the results of the $ATWACC_{BV}$ model with the traditional model to ensure the allowed fair return has not increased or decreased on a relative basis solely as a result of using new regulatory models.

The Board, in the next section, will determine a fair return using a modification to TransAlta's $ATWACC_{MV}$ model.

In summary, for all of the above reasons, the Board finds it necessary to reject TransAlta's version of the ATWACC model which proposes the use of market capitalization ratios. Accordingly, the Board considers that it should place primary weight on the traditional method in the development of a fair return for these proceedings. Nevertheless, the Board considers that useful insights and assistance can be obtained from the principles of the ATWACC concept that will assist it in determining the fair return for the integrated company as well as by business function.

(E) Fair Return Using $ATWACC_{BV}$ Model

Board Findings

The following modifications are necessary to TransAlta's ATWACC results in order to arrive at an allowed fair return and income tax:

- Determine an ATWACC from Dr. Vilbert's sample Canadian and U.S. companies using book rather than market capitalization weightings.
- Determine an appropriate adjustment to the above ATWACC to eliminate any distortion caused by involvement in unregulated activities.
- Determine an appropriate adjustment to ATWACC consistent with Board approved market equity rate of returns
- Adjust the ATWACC for the differences between the embedded and current cost rates of debt and preferred.
- Gross up the adjusted ATWACC return by dividing by one minus the tax rate to arrive at the allowed fair return plus the book income tax.
- Determine the income tax adjustments to be added to the book income tax.

3. GENCO/TRANSCO/DISCO
(i) Return

The Board, for reasons mentioned earlier, considers that the ATWACC should be determined using book capitalization ratios. The Board has reworked Dr. Vilbert's Table No. MJV-10 Panels A-J for the Canadian sample companies and Table No. MJV-19 Panels A-J for the US sample companies to determine ATWACCs based on book capitalization ratios. This results in an approximate 50 basis point reduction to the $ATWACC_{MV}$ determined by Dr. Vilbert using market capitalization ratios.[440]

Dealing with unregulated activities and using TransAlta Utilities as an example, the Board notes that TransAlta Corporation's business activities include regulated and unregulated activities. TransAlta Utilities estimated that 21% of total corporate governance should be allocated to unregulated activities based on 1/3 revenues, 1/3 assets and 1/3 employees.[441] However, the Board notes that this figure increases to 30% if only revenues and assets are considered. The Board considers 30%, at this time, to more accurately describe the portion of TransAlta Corporation's total business activities that represent activities not regulated by the Board. The Board also notes that TransAlta Corporation common shares are traded in the marketplace whereas TransAlta Utilities common shares are not traded in the marketplace. The Board considers that the share price of TransAlta Corporation reflects investor expectations respecting TransAlta Corporation's existing and prospective regulated and unregulated activities.

As a result, the Board considers that the allowed fair return should be based on reasonable investor expectations respecting regulated activities only. Consequently, the Board is not persuaded that the market capitalization ratios of TransAlta Utilities can be estimated from the market capitalization ratios of TransAlta Corporation. Instead, the Board considers that TransAlta Utilities' book capitalization ratios provides a better measure of the true value and cost of Board regulated activities. The Board notes that this reasoning also applies to other firms in the Canadian and U.S. samples which are not pure plays. In this regard, the Board has examined the book ratios of the firms in the Canadian and U.S. samples and is uncertain of the extent to which the book ratios may be distorted by unregulated activities.

However, the Board considers that the above 50 basis point adjustment to the $ATWACC_{MV}$ from market weighted capitalization ratios to book weighted capitalization ratios has also accounted for the majority of unregulated activities.

The Board has further reduced the $ATWACC_{MV}$ by 25 basis points to adjust Dr. Vilbert's market equity rate of return to the 9.00%-9.50% range for the market equity rate of return found appropriate by the Board in the equity return section of this Decision.[442] The Board notes that Dr. Vilbert's mid-point market equity rate of return exceeds the Board's determination by some 60

[440] Appendix 1, p.4
[441] Exhibit 13, Tab 5.3
[442] Appendix 1, p.5

basis points. This increases the ATWACC by some 25 basis points (i.e., a book common equity ratio of 40% times the 60 basis points).

The Board will use the method advocated by Dr. Kolbe to adjust for the differences between the embedded and current cost rates of debt and preferred.

The Board considers that the $ATWACC_{BV}$ should be consistent over a narrow range of book equity ratios. The Board will similarly determine an $ATWACC_{BV}$ by line of business. The Board notes that the management of TransAlta has always had flexibility in determining actual booked capital structures. The Board considers it important, under an increasingly competitive environment, to continue to provide management with the flexibility to determine actual capital structure. The Board considers that both the traditional method and the $ATWACC_{BV}$ method provide the necessary flexibility. However, the Board notes that future fair return, revenue requirements and rates will always be set on the basis of the Board determined capital structures using either the traditional method and/or an $ATWACC_{BV}$ method.

With the above noted modifications, the Board is satisfied that the ATWACC model produces results equal to the traditional model and more importantly the total fair return will not increase or decrease solely as a result of utilizing a different regulatory models or tools.

(i) Integrated After Tax Weighted Average Cost of Capital$_{BV}$

For all of the reasons mentioned in subsections (D and E) above, the Board will adjust TransAlta's proposed $ATWACC_{MV}$ of 6.91% downward by 0.75% (75 basis points) resulting in an allowed $ATWACC_{BV}$ of 6.16%.

The Board will adjust the above $ATWACC_{BV}$ of 6.16% to recognize the embedded cost of debt and preferred in the fair return conclusion section of this Decision.

The Board will now determine ATWACCs by line of business.

(ii) GENCO After Tax Weighted Average Cost of Capital$_{BV}$

The Board accepts the evidence of Dr. Kolbe respecting the differential between the GENCO $ATWACC_{MV}$ and the Integrated $ATWACC_{MV}$. The Board notes that Dr. Kolbe suggested that an $ATWACC_{MV}$ of 6.75% would be appropriate considering a long-term views whereas an $ATWACC_{MV}$ of 7.00% would be appropriate if the focus were solely on the short-term test periods. Applying the Board's adjustment of 0.75% to these recommendations resulted in a range of 6.00% to 6.25% for an $ATWACC_{BV}$ which the Board considers to be appropriate.

The Board will adjust the above $ATWACC_{BV}$ of 6.00% to 6.25% to recognize the embedded cost of debt and preferred in the fair return conclusion section of this Decision.

The Board will also determine an appropriate $ATWACC_{BV}$ for EPGI in the fair return conclusion section of this Decision.

(iii) TRANSCO After Tax Weighted Average Cost of Capital$_{BV}$

The Board accepts the evidence of Dr. Kolbe respecting the differential between the TRANSCO $ATWACC_{MV}$ and the Integrated $ATWACC_{MV}$. The Board notes that Dr. Kolbe suggested that an $ATWACC_{MV}$ of 6.25% would be appropriate considering a long-term view. The Board notes that if the focus were solely on the short term test periods, the differential on transmission would have to offset Dr. Kolbe's 50 basis point differential on distribution. Using the rate base weightings for transmission (23%) and distribution (15%) would produce a transmission differential of 33 basis points or an $ATWACC_{MV}$ of approximately 6.67% (i.e. 7.00%-0.33%). Applying the Board's adjustment of 0.75% to these recommendations results in a range of 5.50% to 5.92% for an $ATWACC_{BV}$ which the Board considers to be appropriate.

The Board will adjust the above $ATWACC_{BV}$ of 5.50% to 5.92% to recognize the embedded cost of debt and preferred in the fair return conclusion section of this Decision.

The Board will also determine an appropriate $ATWACC_{BV}$ for EPTI in the fair return conclusion section of this Decision.

(iv) DISCO After Tax Weighted Average Cost of Capital$_{BV}$

The Board accepts the evidence of Dr. Kolbe respecting the differential between the DISCO $ATWACC_{MV}$ and the Integrated $ATWACC_{MV}$. The Board notes that Dr. Kolbe suggested that an $ATWACC_{MV}$ of 8.00% would be appropriate considering a long-term view whereas an $ATWACC_{MV}$ of 7.50% would be appropriate if the focus were solely on the short-term test periods. Applying the Board's adjustment of 0.75% to these recommendations results in an $ATWACC_{BV}$ range of 6.75% to 7.25% which the Board considers to be appropriate.

The Board will adjust the above $ATWACC_{BV}$ of 6.75% to 7.25% to recognize the embedded cost of debt and preferred in the fair return conclusion section of this Decision.

(4) Equity Rate of Return

In determining a fair return for a utility, regulatory tribunals have traditionally accepted the forecast embedded cost of debt and preferred shares and have set a rate of return on the equity component of capital structure. As an alternative method of determining a fair return, TransAlta's expert witnesses proposed using ATWACC, discussed in a previous other section. The cost of debt and preferred equity has also been discussed in previous sections. This section will set out the results of the expert witnesses and the positions of the various parties on the rate of return on equity.

Generally, expert witnesses have employed three tests to estimate the rate of return on equity. These tests are the comparable earnings test, the discounted cash flow (DCF) test and the equity risk premium test. Each of these tests attempts to determine the rate of return that an investor would require on another investment of equal risk to a utility. The details of the methods employed in these tests are well known. Despite the seeming precision of the financial tests, each expert witness employs judgment in making a final recommendation. Accordingly, the Board must give weight to the financial tests and ultimately employ its own judgment in determining a rate of return for the electric industry.

Because the structure of the electric industry is in change, the data required to determine the cost of capital for each regulated component of the industry, generation, transmission and distribution, is extremely limited. This section of the Decision will determine a cost for the equity component of capital structure for an integrated electric utility. In another section of this Decision, the relative business risks of each industry function will be discussed and evaluated.

Position of TransAlta

TransAlta provided two witnesses, Drs. Kolbe and Vilbert. The ATWACC evidence provided by these witnesses is reviewed in another section of this Decision. Although the TransAlta witnesses directed their evidence primarily towards the ATWACC method, Dr. Vilbert performed conventional tests of cost of capital in support of the ATWACC evidence. Dr. Vilbert did not provide estimates based upon the comparable earnings method, because he believed the problems inherent in the model are too great to be reliably overcome. Dr. Vilbert considered that the book return used in the comparable earnings test did not equal the true return, which he defined as the firm's cash flow plus the change in the economic value of the firm's assets, divided by the initial value of the assets. Dr. Vilbert further noted that accounting returns are reported differently by different firms, reducing the value of comparisons. Dr. Vilbert estimated the equity rate of return of his sample companies, using both DCF and risk positioning evidence. Risk positioning is identical to the equity risk premium test[443].

With respect to his DCF Studies, Dr. Vilbert noted that the current uncertainty in the electric utility industry meant that the longest-horizon growth rate forecasts available were far too short to give reliable cost of capital estimates with the DCF method. Dr. Vilbert considered that the currently available forecasts cover a period of turmoil and restructuring for the industry, which bias the estimated growth rates and, hence, the DCF results downward. Dr. Vilbert described his DCF results as "erratic" and concluded that the conditions for the DCF test to give reliable results were not satisfied. Dr. Vilbert considered his DCF results on a sample of Canadian companies served as a lower-bound comparison to the results from the risk positioning model.

Dr. Vilbert's preferred method of estimating the cost of equity was the risk positioning or equity risk premium method. Dr. Vilbert noted:

[443] Exhibit 13, Direct Evidence of Michael J Vilbert, page C-1

> This approach may sometimes be applied formally. For example, an analyst or a board may check the spread between interest rates and what is believed to be a reasonable estimate of the cost of capital at one time, and then apply that spread to changed interest rates to get a new estimate of the cost of capital at another time.[444]

Dr. Vilbert estimated that the long-term market risk premium for Canadian securities was 5.3-6.11%. For U.S. securities, Dr. Vilbert estimated the market risk premium was approximately 7% for securities of average risk. Dr. Vilbert considered that the Canadian data was too volatile to be reliable and examined the relationship between the TSE 300 and the Standard and Poor 500 to conclude that the strongest evidence for the Canadian market risk premium was 7%. Dr. Vilbert estimated the beta or relative risk for Canadian and U.S. electric utilities and applied the betas to CAPM and ECAPM models to estimate the cost of the equity portion of capital.

Dr. Vilbert did not include an allowance for flotation costs. However, in response to BR.TransAlta-45, Dr. Vilbert considered that a flotation cost adjustment of between 50 and 100 basis points would be reasonable.

The following table provides the range of equity rates of return resulting from Dr. Vilbert's studies.

Test	Component	Component	Flotation Allowance	Test Result	Weight
Comparable Earnings	N/A	N/A	N/A	N/A	None
Discounted Cash Flow	Dividend 3.2-7.1%	Growth (3.2)-11.4%	(not used) 0.50-1.00%	2.5-16.3%	Little
Risk Positioning US Sample	N/A	N/A	(not used) 0.50-1.00%	9.2-10.9%	Most
Risk Positioning Canadian Electric Sample	N/A	N/A	(not used) 0.50-1.00%	8.4-10.4%	Most
Risk Positioning Canadian Sample	N/A	N/A	(not used) 0.50-1.00%	8.3-10.3%	Most
Point Estimate				11.1%	

Dr. Vilbert considered it likely that TransAlta is near the top of the range for the Canadian sample but is probably near the bottom of the range compared to the U.S. sample. The sample average results of the two samples for the most reliable of the various estimation methods imply

[444] Exhibit 13, Direct Evidence of Michael J Vilbert, page C-2

a range of 6.00% to 7.25%% for the after-tax weighted-average cost of capital for Canadian electric companies and 6.75% to 8.25% at the risk level of U.S. utilities facing restructuring. In Dr. Vilbert's opinion, deregulation and restructuring are the most important risk factors facing companies in the electric industry at this time. The U:S. sample is comprised of firms that are further along in restructuring than TransAlta and face more business risk than TransAlta has in the past. It is quite likely that TransAlta's ATWACC lies above the sample average range for the Canadian sample companies. Therefore, TransAlta's cost of capital should be no lower than the lower end of the range for the U.S. sample companies even though that range is at the top of the range for the Canadian sample.

Dr. Vilbert's risk positioning analysis concluded that an estimated a range of 6.75 to 7¼% for ATWACC would be appropriate for TransAlta. Dr. Vilbert considered 7% to be the best point-estimate for TransAlta's ATWACC.[445] At the capital structure underlying TransAlta's cost of service presentation, Dr. Vilbert estimated the cost of equity would increase to a level in the range of 10.5% to 11.7% for 1999 and 11.6% for the year 2000. Dr. Vilbert obtained a point estimate of 11.1% return on equity, corresponding to 7 percent ATWACC.

In argument, TransAlta questioned the five measures of risk employed by Drs. Waters and Winter. TransAlta considered that Dr. Vilbert had shown that only one of the five measures, beta, has a sound foundation in financial theory[446]. TransAlta submitted that the evidence of Drs. Waters and Winter on beta should be disregarded since they did not calculate the standard deviation of total returns of the stock (i.e. inclusive of dividends), which is the traditional measure of shareholder return. TransAlta noted that Drs. Waters and Winter admitted that three of their risk factors have not been subjected to academic testing. TransAlta submitted that these measures cannot be relied upon to determine the risk/return tradeoff. The final measure used by Drs. Waters and Winter, standard deviation of returns, has been shown to be related to total risk and not to systematic risk, which is the risk that is related to required return.

In reply, TransAlta submitted that the COCI was incorrect that Dr. Vilbert neglected to compensate for the change in the market wide risk premium that would result from including the difference between rate base and total assets. TransAlta submitted that the adjustment to beta used in Dr. Vilbert's analysis already considered the correction necessary to compensate for the change in the market risk premium. The amount of change in the beta of firms regulated on the basis of original cost rate base was very carefully determined to ensure consistency when the beta is to be used against an index consisting only of equity securities.

TransAlta defended Dr. Vilbert's use of betas based on U.S. data to determine the beta for Canadian companies. TransAlta explained that beta is merely a number which measures the relative systematic risk of a company to the market as a whole. TransAlta agreed that the U.S. and Canadian economies and electric utility industries may differ but considered that they are

[445] The Board notes that using this reasoning, Dr. Vilbert's point estimate of the equity rate of return before weighting with market capitalization and converting to an ATWACC would be approximately 9.2% to 10.4%.

[446] Exhibit 16 pages 14-17

economically and physically linked. TransAlta submitted that the relative risk (adjusted beta) of companies in the electric utility industry undergoing restructuring would be similar to the electric industry in Canada undergoing a similar restructuring. This did not mean that Dr. Vilbert considered that the Alberta restructuring was identical to that in the U.S. TransAlta submitted that Dr. Vilbert used the U.S. sample as one benchmark to position TransAlta's risk, and concluded that TransAlta has less risk overall.

TransAlta considered that the risk premium recommendation of only 2.25 percent by Drs. Waters and Winter represented a decrease from the 3.25 to 3.75 percent equity risk premium in the most recent Board decision. This recommendation, along with the capital structure recommendations did not account for the increase in the industry's risk due to restructuring and to the introduction of competition into the industry. TransAlta considered that its witnesses had made recommendations that recognized the increased risk of the industry and had provided an estimate of the cost of equity, which is consistent with the requested capital structure.

Position of EPGI/EPTI

EPGI and EPTI provided a witness and evidence on the matter of a fair return on equity. Dr. Evans performed three tests to estimate the cost of equity capital for an electric utility.

Dr. Evans performed an analysis of the rates of returns for 15 high-grade and 14 non-resource companies for the period 1988-97. He gave equal weight to both samples and greater weight to returns in the 1988-97 period and less to the 1994-97 subperiod. Because the median rates of return were 0-90 basis points less than average returns, Dr. Evans concluded that earnings were depressed during the time period studied. Applying his judgment to the results, Dr. Evans determined that the appropriate prospective rate of return for the lowest-risk companies, to which EPGI/EPTI were comparable, was 11-12%.

In his DCF test, Dr. Evans used the same reference group of companies in his comparable earnings test to estimate the dividend and growth components for his DCF test. Dr. Evans considered that the traditional growth series, earnings per share, dividends per share and book value per share, provided reliable estimates of investor expectations of growth. Dr. Evans proposed using the "br" series, i.e. the growth in the return on book equity times the expected retention ratio. Based on both samples, Dr. Evans concluded that the growth component of the DCF test, based on "br", was 8.4% and dividend yield component was 1.25-1.50%.

Dr. Evans forecast the rate for long Canadas to be 5.5-6.0%. Dr. Evans directly measured the equity risk premiums of his reference groups relative to long Canada bond yields to determine an equity risk premium for his sample of 4.0-4.5%, focusing on the midrange of 4.25%. Dr. Evans compared the risk premium for his reference group and found it compared favourably the market premium for the Hatch and White study and was lower that the market risk premium determined by the Ibbotson and Canadian Institute of Actuaries studies. In a supplement to his evidence, Dr. Evans argued that the globalization of world markets required that regulators take note of the

alternative investment opportunities available to Canadian investors in awarding rates of return on equity. However, Dr. Evans made no explicit adjustment for foreign returns in his tests.

To both his raw DCF and equity risk premium tests, he added 60-120 basis points in order to provide for a market-to-book ratio of 110-120% and a payout ratio of 65%. This would compensate the investor for market pressure and financing costs.

Dr. Evans noted that Canadian regulators have recognized the limitations of the DCF test, including the Board in Decision U97065. Accordingly, Dr. Evans gave "virtually no weight" to the DCF test. He considered that equal weight should be given to his equity risk premium test and to the comparable earnings test.

The results of his tests are summarized as follows:

Test	Component	Component	Flotation Allowance	Test Result	Weight
Comparable Earnings	N/A	N/A	N/A	11-12%	50%
Discounted Cash Flow	Dividend 1.25-.50%	Growth 8.4%	0.65-1.15%	10.4-0.9%	No Weight
Equity Risk Premium	Risk-free Rate 5.5-6.0%	Risk Premium 4.25%	0.6-1.2%	10.6-1.2%	50%
Recommendation				11%	

In rebuttal evidence, Dr. Evans noted that the ROE recommendation of Drs. Waters and Winter would result in interest coverage ratios that would not support EPGI/EPTI's current bond ratings. Dr. Evans defended his equity risk premium based on his low-risk samples and considered that Drs. Waters and Winter had incorporated a "loser bias" in their estimates by using in their analysis companies of average risk. Finally, Drs. Waters and Winter had ignored the expansion of risk premiums as interest rates decline

In argument, EPGI stated that common equity investors in 1999/2000 would evaluate the long-term risks in arriving at their decisions respecting required rates of return. In EPGI's opinion the long-term risks include risks that will exist during the PPA period, and, thus, there is a need to examine revenue requirements, risks and prospective rates of return on a plant-by-plant basis. EPGI considered that the proposed 11.0% rate of return on common equity was insufficient to compensate for the operating leverage risks faced by the Rossdale plant in 1999 and 2000 and the Clover Bar plant in 1999. However, EPGI did consider that the 11.0% rate of return on

common equity was sufficient for the 1999 and 2000 revenue requirements for Genesee and the 2000 revenue requirement for Clover Bar.

EPGI noted that Dr. Vilbert converted his ATWACC recommendation to an equity rate of return point estimate of 11.1%, supporting Dr. Evans' recommendation, even though they used different approaches.

EPGI considered that the restructuring of the Canadian economy in the early 1990s gave rise to an extraordinarily low level of experienced corporate profitability that was inconsistent with the long-run profit expectations of investors. Thus, the comparable earnings rates of return were not particularly useful, because those experienced rates of return were not reliable indicators of investor expectations. However, EPGI considered that the restructuring of the Canadian economy which occurred primarily during 1990-93 was complete. Since corporate profits have returned to more normal levels, it was possible to utilize several years of post-restructuring return rates in the context of a properly applied comparable earnings test. EPGI submitted that the Board should give substantially greater weight to the results of applying the comparable earnings method than it did in Decision U97065.

Since neither Dr. Evans nor Drs. Waters and Winter gave weight to the discounted cash flow method, EPGI considered that this method required no further discussion.

EPGI considered the fact that, since Dr. Evans' risk premium conclusions were based on a wide variety of data, the Board should place greater emphasis on his risk premium conclusions *vis-à-vis* the risk premium conclusions of others whose risk premium analyses focus only on one particular type or source of data. EPGI concluded that the 11.0% value was within the ranges indicated by both the comparable earnings and equity risk premium methods so that the 11.0% conclusion was not materially affected by the formal weights given to each of the two methods.

EPGI considered that an evaluation of a return witnesses' recommendations would necessarily focus on the combined effect of both capital structure and rate of return – i.e., the effect on interest coverage ratios. In Decision E93060, the Board recognized that coverage ratios were a significant indicator of credit quality and do provide a means of dealing with the complex interrelationships between the components of capital structure and the cost rates of each component. EPGI noted that the 11.0% applied-for rate of return on common equity produces an interest coverage ratio 1.9-2.0x using EPGI's forecast actual capital structure ratios. The 8.25% rate of return recommendation of Drs. Waters and Winter results in coverage ratios of 1.4x for EPTI based on the forecast actual capital structure ratios of EPTI. This was inconsistent with the 1996 the City of Calgary Electric System (CCES) Report wherein Dr. Waters recommended a 47.5% deemed common equity ratio for the transmission operations of CCES . Dr. Waters specifically rejected a lower common equity ratio for CCES in 1996, because that lower common equity ratio would only produce coverage ratios of 1.9-2.1x.

EPGI stated that this examination shows that the combination of an 11.0% rate of return on common equity and the applied-for capital structure ratios of EPGI and EPTI produces interest coverage values that would almost surely have been rejected by Dr. Waters as insufficient. EPGI submitted that the even lower interest coverage values resulting from an 8.25% rate of return on common equity demonstrated that the Waters and Winter recommended rate of return is clearly unreasonable.

EPGI disputed the proposition of Drs. Waters and Winter that risk premiums do not expand as bond yields decline below 10%. First, the Waters and Winter model does not predict constant risk premiums at bond yields below 10%. The model applied to the McShane data predicts "bare bones" risk premiums (i.e., excluding flotation costs) that vary from negative 0.85% to 2.97% at bond yields of 2.0% to 9.25%. EPGI noted that when the Waters and Winter model was applied to the data of Dr. Morin and Ms. McShane, the predicted risk premiums shrink as bond yields decline from about 9.25%. EPGI stated that it was not aware of any finance theory, regulatory board or expert on these matters that has ever taken the position that risk premiums shrink as bond yields decline. EPGI concluded that neither data set confirmed the proposition that risk premiums are constant below 10% even using the model developed by Drs. Waters and Winter.

Finally, EPGI noted that Drs. Waters and Winter had presented their "non-expansion" hypothesis before regulatory tribunals in British Columbia, Newfoundland, Quebec and the National Energy Board. In all cases, the Waters and Winter hypothesis was rejected. EPGI submitted that there was no reasonable basis and no empirical evidence to support the proposition that risk premiums fail to expand as bond yields decline below 10%. Indeed, there are valid theoretical reasons arising from the differential taxation of interest, dividends and capital gains to support the continued expansion of risk premiums at bond yields below 10%.

EPGI also cautioned against using the July 1998, Newfoundland Light & Power (NLP) rate of return on common equity award of 9.25%. Subsequent to this decision, CBRS put NLP on "Credit Alert" and then downgraded its long-term debt from A to A (Low). Investors sold off the debt securities; and yields rose to levels consistent with the lower rating. Bondholders who purchased NLP long-term debt with an A rating saw the financial integrity of their investments impaired by a regulatory decision that led to the downgrade. EPGI noted that this was contrary to the conclusions of Drs. Waters and Winter that the financial integrity of NLP was not impaired.

EPGI also did not consider that the ROE of EPGI/EPTI should be benchmarked to the same rates of return on common equity as AE and TransAlta. EPGI noted that Drs. Waters and Winter characterized AE and TransAlta as "...high grade utilities, holding the highest bond ratings among Canadian utilities. The median CBRS bond ratings for the groups of 10 and 15 *lowest-risk* utilities are both A (High). In contrast, EPGI's CBRS bond rating is a B++, a full seven rating "notches" below the A+ CBRS bond ratings for Canadian Utilities and TransAlta. EPGI submitted that the debt costs of EPGI and EPTI are demonstrably higher than those of AE, TransAlta, the groups of lowest-risk utilities said to be of similar risk to AE and TransAlta and

the group of lowest-risk non-utilities said to be of greater risk than AE and TransAlta. Therefore, by the relative risk measures developed by Drs. Waters and Winter, the fair rates of return on common equity for EPGI and EPTI should be at least 75 basis points higher than the fair rates of return on common equity for AE and TransAlta. The evidence on Pacific Northern Gas (PNG) supported this, the only utility in the group of 15 companies whose CBRS bond rating is the same as EPGI's. EPGI noted that the BCUC and Dr. Waters both acknowledge that 75 basis points higher rate of return is required for PNG compared to the required rates of return for high quality, low-risk benchmark utilities such as BC Gas.

EPTI confirmed its support of Dr. Evans' 11.0% recommendation for a rate of return on equity.

In reply, EPGI/EPTI submitted that the COCI and FIRM Customer argument ignored important evidence concerning loser bias. The risk premium evidence of Dr. Evans developed from historical returns of low risk companies was more likely to provide actual rates of return experienced consistent with investor expectations and is, therefore, more useful for the purpose of estimating the investors' required rate of return. Furthermore, COCI and the FIRM Customers failed to recognize the relevance of the comparable earnings method and results. Dr. Evans' comparable earnings study was unchallenged and that study lead to an 11.0-12.0% rate of return on common equity. Until the late-1980s and early 1990s, the comparable earnings method was the most prominent method used by Canadian regulators to establish rates of return on common equity for utilities. EPGI submitted that the circumstances that caused the Board (and the NEB) to place less reliance on the comparable earnings method did not apply to any substantial degree in 1999/2000.

EPGI/EPTI disagreed with the COCI that the Board should merely "update" Decision U97065. By the COCI's own admission, its witnesses were about 100 basis points "out of the ballpark" using the update method. EPGI/EPTI noted that 9.125% is similar to the 9.25% decision for NLP at approximately the same bond yield level. EPGI/EPTI considered that decision had resulted in a downgrading of NLP's bonds and a collapse of the Fortis share price. In short, the capital markets and the bond rating agencies were unimpressed with rates of return at the 9.25% level. EPGI/EPTI submitted that an 8.0-8.25% rate of return would receive a considerably more chilling reception.

In the opinion of EPGI/EPTI, the COCI also ignored the expansion of bond yields as interest rates decline. The COCI update method also gave no substantive weight to the 11.0-12.0% rate of return conclusion from applying the comparable earnings method. EPGI/EPTI considered the 9.125% proffered by COCI was determined in the context of "high grade utilities" such as AE and TransAlta and not lesser quality, higher risk utilities such as EPGI and EPTI. An adjustment for this risk difference alone should be no less than 75 basis points.

EPGI/EPTI considered that the FIRM Customers ignored evidence that lower coverage ratios and non-taxability lead to higher financial risks that are not compensated for in EPGI's applied-for capital structure ratios. The FIRM Customers further ignored the fact that EPGI's low

coverage ratios and non-taxability are an important factor in determining EPGI's bond rating. The FIRM Customers ignored the fact that Dr. Waters considered the relatively low coverage ratios and non-taxability of the CCES important in determining the appropriate capital structure for CCES' transmission operations in 1996. EPGI/EPTI concluded that the "traditional" rate of return experts in this proceeding all agreed that coverage ratios and non-taxability affect financial risk and therefore capital structure and/or rate of return on common equity.

EPGI/EPTI disagreed with the proposition of IPPSA/SPPA that the presence of deferral accounts should result in a lower return on equity, EPGI/EPTI noted that IPPSA/SPPA made no quantitative recommendation in respect of the rate of return adjustment, provided no substantive analysis to support its claim, did not indicate which deferral accounts should be taken into consideration and how they should be "weighted" in arriving at the claim of a "reduced" rate of return and did not cite any expert evidence or regulatory precedent to support its submission. EPGI submitted that IPPSA/SPPA's argument for a reduced rate of return arising from the implementation of deferral accounts was incomplete at best and should not be relied on by the Board.

EPGI/EPTI considered the FIRM Customers' proposals with respect to deferral accounts to be as vague as those of IPPSA/SPPA. EPGI/EPTI noted that neither IPPSA/SPPA nor the FIRM Customers nor any other intervenor challenged the evidence of Dr. Evans respecting the impact of deferral accounts on common equity ratios and rates of return on common equity for EPGI.[447] EPGI/EPTI concluded that the Board should approve the applied-for 11.0% rates of return on common equity for EPGI and EPTI.

Position of the COCI

The COCI, consisting of ENMAX, EAL, IPCAA and LE/RD, presented Drs. Waters and Winter as expert witnesses on the cost of capital. Dr. Waters and Winter did not perform a comparable earnings test because of two concerns. First, Drs. Waters and Winter considered that the concept of comparable earnings did not necessarily have any relationship with the concept of a fair return. Secondly, Drs. Waters and Winter considered that the measurement of comparable earnings, which were based on accounting data, provided results that were difficult to compare across companies and across time.[448] Dr. Waters and Winter also did not perform a DCF test in estimating the cost of capital.

Drs. Waters and Winter focused on the equity risk premium method as providing the most reliable and stable measure of cost of capital. Drs. Waters and Winter relied on five studies[449] of Canadian financial markets and a geometric mean to estimate a market risk premium range of 4.0-4.50%. Drs. Waters and Winter chose the higher end of this range for the market risk

[447] Tr. pages 4838-4839
[448] Exhibit 162, pages 118-122
[449] Canadian Institute of Actuaries, Hatch and White, Gordon and Gould, Scotia Mcleod Inc. and the Government of Canada "*The Retirement Income system in Canada: Problems and Alternative Policies for Reform*"

premium, having regard to the higher risk premiums experienced by Canadian equities in recent years and the higher risk premiums for the U.S. markets. In the opinion of Drs. Waters and Winter, high-grade utilities required, at most, half the market premium or 2.25%, based on a study of measures of volatility. Drs. Waters and Winter considered the prospective risk-free rate to be 5.5%, based on the December 1998 Consensus forecast of long Canada bonds of 5.2%. At the time of the hearing, Dr. Waters noted that the current long Canada rate was 5.62%.
Dr. Waters considered that daily fluctuations of 10 basis points were not unusual and that the current rise in the long Canada rate was temporary. Dr. Waters saw no reason to revise his risk-free recommendation since this volatility was well within the 25-50 points he and Dr. Winter allowed for volatility[450].

Drs. Waters and Winter did not consider that flotation costs were required to be added to the investors' rate of return. In the opinion of Drs. Waters and Winter, dilution represented only one of the many risks faced by an investor that were already included in the equity risk premium. They concluded that any explicit allowance for dilution effectively represents a safety factor rather than an element required to provide investors with fair treatment. They did, however, incorporate a margin of safety of 25—50 basis points in their recommended fair rate of return[451] to allow for, primarily, uncertainty in capital markets over the test period. The following table summarizes the recommendations of Drs. Waters and Winter:

Test	Component	Component	Flotation Allowance	Test Result	Weight
Comparable Earnings	N/A	N/A	N/A	N/A	None
Discounted Cash Flow	Dividend N/A	Growth N/A	N/A	N/A	None
Equity Risk Premium	Risk-free rate 5.5	Risk Premium 2.25%	.25-.50%	8.0-8.25%	100%
Recommendation				8.25%	

Drs. Waters and Winter provided evidence on the relationship between the required return on equity and long-term interest rates.[452] Based on data for 1979-1996 provided by Ms. McShane and 1980-1994 data used by Dr. Morin, Drs. Waters and Winter concluded that there was no evidence that equity risk premiums increased as interest rates decreased below 10 percent. While Drs. Waters and Winter conceded that the equity risk premium may decline at interest rate

[450] Tr. p.5249-5251
[451] Exhibit 162, p.104-105.
[452] Exhibit 162, p.72-86.

levels above 10%, they concluded that this was merely the effect of an inflation risk premium. Drs. Waters and Winter noted that the NEB had introduced a negative relationship between risk premium and interest rates in its generic ROE formula. However, Drs. Waters and Winter considered that the NEB model was "flawed".

Drs. Waters and Winter considered that Dr. Evans' estimates of the achieved risk premiums in his samples of low risk non-utilities were subject to both "survivor bias" and "success bias." Drs. Waters and Winter concluded that Dr. Evans' shed no light on the premiums prospectively required by investors in non- utilities comparable in risk to low risk utilities.

In argument, the COCI considered that the starting point for analysis in this case should be the Board's decision in the last one, Decision U97065. The COCI considered that the most dramatic and most important change in facts since Decision U97065 had been issued was the decline of approximately 200 points in interest rates. In the opinion of the COCI, the change in interest rates must have an effect on the rate of return on equity. The second important change noted by the COCI was the 1998 amendment to the EU Act, which defined the post-2000 regulatory regime, raising the question of the effect of that legislative change on business risk.

In Decision U97065, the COCI noted that the Board gave little weight to the comparable earnings test for the purposes of determining an appropriate rate of return. The Board considered the results obtained from the comparable earnings test only as a check on the results of the market-based tests. The Board indicated that it considered the DCF model to have theoretical validity, but found that recent economic conditions may understate historic growth rates. The Board also assigned little weight to the DCF test, viewing it only as a reasonability test of its final conclusion on return on equity. The Board gave primary weight to the results of the equity risk premium test in determining a return on equity for electric utilities in the 1996 test year.

The COCI calculated that, if one were to apply the same methodology as was applied by the EUB in Decision U97065, the result would be a range for equity rate of return of 8.75–9.50, with the mid-point being 9.125%. In Decision U97065, the Board established a range of 7.50–8.00% for a risk-free rate based on the upper and lower estimates of the expert witnesses. In these proceedings, the upper limit is established by Dr. Evans who used a range of 5.50 to 6.0%, the midpoint being 5.75.[453] Drs. Kolbe and Vilbert are at 5.70%.[454] The lower limit is established by Drs. Waters and Winter at 5.50%.[455] The COCI considered that the Board would conclude that the range in this proceeding would 5.50–5.75%, reflecting the dramatic reduction in interest rates that has occurred. The COCI noted that the Board found an equity risk premium in the range of 325–375 basis points, inclusive of all adjustments, in Decision U97065. The COCI assumed the Board might be inclined to retain its 325–375 basis point adjustment, given that the expert witnesses in this proceeding continue to disagree on the equity risk premium. If one were

[453] Exhibit 4, Evidence of Robert E. Evans dated October 30, 1998 on Behalf of Edmonton Power Generation Inc. and Edmonton Power Transmission Inc., "Evans Evidence," p. 6.

[454] Tr. p.5105.

[455] Exhibit 162, p.88

to add 3.25–3.75% to 5.50–5.75% risk-free rate, the COCI concluded that the Board would find a range of 8.75–9.50% to be reasonable. The mid-point of this range is 9.125%.

The COCI noted that Dr. Evans' sought a return on equity in the range of 10.75–11.5%, focusing on 11.0% (other than for the Clover Bar and Rossdale generating stations, for which minimum return margins of 15.75% and 26.25%, respectively, were requested).[456] The COCI considered the recommendation of 11% was unreasonable. The COCI considered this was obvious from a simple consideration of the last decision and current interest rates. Dr. Evans relied on comparable earnings, DCF and equity risk premium tests and upon a negative relationship between risk premium and long-term interest rates. The COCI submitted that the evidence in this case shows clearly that there is no negative relationship when rates on long Canada bonds have been below 10%. The COCI urged the Board to reject the "negative relationship" theory and accept the view advocated by Drs. Waters and Winter.

The COCI submitted that Drs. Waters and Winter have provided the conceptual and empirical analysis that shows beyond doubt that the risk premium does not and should not vary with long-term interest rates when those interest rates are below 10%. In other words, no adjustment of an historically estimated risk premium is necessary to reflect current low interest rates

The COCI submitted that its cross-examination of Dr. Evans revealed that his analysis of the negative relationship was seriously flawed. Dr. Evans had filed extensive evidence and introduced exhibits to assist the discussion[457]. The COCI considered that Dr. Evans' conclusion of the negative relationship below 10% rested on the fundamentally flawed assumption that the linear regression analysis required a common intercept point. If the analysis were performed correctly, with two separate regressions, the COCI submitted that there is no negative relationship between the equity risk premium and interest rates for interest rate values of less than 10%.[458] The COCI concluded that the so-called negative relationship between the equity risk premium and interest rates had been disproved for interest rates below 10% and had increased the credibility of the 8.0–8.25% recommendation of Drs. Waters and Winter.

The COCI noted that TransAlta sought adoption by the Board of the ATWACC approach. ATWACC would result in a return on equity of 11.2% if the 40% common equity component established in U97065 were utilized. The COCI concluded that the extreme numbers for risk premium and return on equity that fall out of the ATWACC recommendation of Drs. Kolbe and Vilbert were sufficient to warrant their rejection.

The COCI disagreed with Dr. Vilbert's adjustment of beta. The COCI submitted that Dr. Vilbert used the estimated beta from the set of all assets but then, rather than using a "market wide" risk premium for the set of all assets, he applied the beta only to equities, namely the TSE 300. The

[456] Exhibit 4, Evidence of Robert E. Evans, p.7
[457] Exhibits 148-152.
[458] Tr. p.4785.

COCI noted that this "missing asset" adjustment served to increase the risk premium. The COCI also disagreed with Dr. Vilbert's use of betas for U.S. electrical utilities. The COCI considered this constituted "an indefensible error of analytical logic."

In reply, the COCI submitted that TransAlta did little more than assert ATWACC was true because it was so theoretically obvious. The COCI asserted that it was apparent Drs. Kolbe and Vilbert never analyzed their own data to determine if the cost of capital was similar over a broad range of companies and capital structures. When such analysis is undertaken, the empirical data provided by Dr. Vilbert disproves the theorizing of Dr. Kolbe and disproves the fundamental theory underpinning ATWACC for the Canadian utility industry. The COCI noted that the FIRM Customer argument[459] had demonstrated that Dr. Vilbert's Canadian utility sample shows increasing ATWACC as the equity percentage increases, contrary to theory The COCI submitted that the Board must determine the cost of capital for a regulated utility company excluding unregulated activities. The COCI considered that ATWACC was based on a market value of equity capital and required the Board to make an ROE determination for a company with both a preponderance of regulated utility businesses as well as a significant number of riskier, unregulated activities. The COCI concluded that TransAlta would have the Board abdicate its responsibility and include unregulated activities in the ATWACC-based cost of capital for regulated utility service.

Position of AE

AE submitted that any findings made with respect to the other Applicants should not be of a generic nature and should not form a precedent for AE in future proceedings. AE stated that this was particularly true with respect to the establishment of an appropriate capital structure for each of the functions (i.e. generation, transmission and distribution) for the subject utilities. AE requested the Board to indicate specifically that its findings are applicable only to the subject companies and pertain only to the prevailing circumstances.

Position of the FIRM Customers

The FIRM Customers recommended a return on common equity for TransAlta of 8.0-8.25% consistent with the analysis of Drs. Waters and Winter. The FIRM Customers noted that the 5.5% estimate of the risk-free rate of Drs. Waters and Winter used more recent data than Dr. Vilbert's estimate and was within two basis points of the rate at the time of the hearing. The market risk premium of Drs. Waters and Winter is a long-term estimate of Canadian market risk premia, adjusted upward judgmentally to rely more heavily on data in the last half of the period and on the higher U.S. market risk premium. The FIRM Customers considered they provided significant information suggesting their recommended allowance is generous and reliance on raw U.S. market data is inappropriate. The FIRM Customers noted that Dr. Vilbert provided another reason why reliance on U.S. market data may be questionable and biased upward, namely the less favourable tax treatment of dividends in the U.S.

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[459] FIRM argument, pp. 23-26 and Figure 1-B, p.25]

3. GENCO/TRANSCO/DISCO
(i) Return

The FIRM Customers supported the evidence of Drs. Waters and Winter that showed fixed income securities required higher returns (i.e. a "purchasing power premium") during periods of high, volatile and uncertain inflation. Equity holders, with some ability to increase prices as costs increased, did not require this premium thereby narrowing the risk premium during periods of high interest rates. The FIRM Customers agreed with Drs. Waters and Winter that, during periods of lower interest rates, the purchasing power premium is likely to be less. This reflected not just lower inflation expectations, but lower variance in those expectations. Drs. Waters and Winter analyzed a more sophisticated polynomial model clearly producing a better fit, while Ms. McShane and Dr. Morin originally produced linear models, to show a rising risk premium as interest rates fell. The better fit showed flat equity risk premia when interest rates were below 10%.

In the opinion of the FIRM Customers, the importance of the flat premium below 10% interest rates indicated that a fair rate of return could be calculated from the award of Decision U97065. The FIRM Customers noted that Long Canada bonds were currently yielding 5.5 to 5.7%. Therefore, the same risk premium the Board adopted the last time would yield a return of 9% to 9.25%.

The FIRM Customers noted that the Utility witnesses relied largely on the risk premium method, with the exception of Dr. Evans' use of comparable earnings. The FIRM Customers noted that the basic results obtained by Drs. Waters and Winter and Dr. Vilbert were quite similar. Dr. Vilbert's raw Capital Asset Pricing Model (CAPM) analysis and Drs. Winters and Waters' risk premium analysis produced very similar numbers, in the vicinity of an 8% return on equity, comparing Dr. Vilbert's estimates of the cost of equity capital for his sample of Canadian utilities to the equity risk premium test developed by Dr. Waters and Dr. Winter. Although there were differences in components of the two tests, the net result was a difference of only about 50 basis points or less in the raw return on equity between the witnesses using these data.

The FIRM Customers considered that Dr. Vilbert modified his CAPM model results in two separate, inappropriate and duplicative ways. First, Dr. Vilbert adjusted the observed betas upwards based on correlation between utility share prices and bond interest rates. This adjustment raised his recommended rate of return by 1.2%. Secondly, Dr. Vilbert used an Empirical CAPM (ECAPM) method. The FIRM Customers noted that the California Public Utilities Commission rejected ECAPM in no uncertain terms. The FIRM Customers considered that ECAPM essentially flattens out the line developed from the standard CAPM method, raising the alleged return required for all stocks with a beta less than one (i.e., those less risky than the market as a whole). The FIRM Customers considered ECAPM has the effect of asking the Board to assume the "risk free" rate of return that is a key element of CAPM was actually 1-2% higher than reality. The FIRM Customers calculated that Dr. Vilbert ended up raising the rate of return on his Canadian utility sample by 0.6-1.2%. The FIRM Customers noted that Drs. Waters and Winters provided a detailed response to Dr. Vilbert's proposal to increase utility betas from their raw levels in Appendix V of their testimony. Dr. Vilbert also asked the Board to consider the cost of capital for a sample of irrelevant U.S. utilities with heavy nuclear and

stranded cost exposure. Finally, Dr. Vilbert makes an inappropriate capital structure adjustment falling out of the ATWACC theory. The FIRM Customers submitted that this demonstrated how 8% became approximately 11%.

The FIRM Customers noted that Dr. Evans relied on comparable earnings and equity risk premium approaches largely based on comparable non-utility companies. The FIRM Customers submitted that the Board has not placed significant weight on comparable earnings in recent years and should not change its approach now. The FIRM Customers considered Dr. Evans' equity risk premium calculations, based on only 15 companies, suffered from "survivor bias" (looking backward over time after the fact to develop a list of low-risk companies) and "success bias" (defining as low risk those companies that experienced less pressure on share prices in the recent downturn, and by definition finding firms whose performance was better than the market as a whole during that time period).

The FIRM Customers disagreed that EPGI/EPTI needed more money because of lower coverage ratios and non-taxability. The lack of preferred stock is one reason leading to low interest coverage ratios. The FIRM Customers noted that financial agencies largely view preferred stock as equivalent to debt. The FIRM Customers submitted that the lack of income taxes should also not be treated as a strong negative. Notwithstanding the foregoing, the FIRM Customers acknowledged EPGI and EPTI may require a slightly higher return than larger utilities with higher bond ratings if the Board were to adopt Drs. Waters and Winter's recommendation of an 8.25% return on equity for TransAlta. A slightly larger cushion may be required for EPGI/EPTI to recognize its smaller size, lower coverage ratios and the bond ratings of these entities. The FIRM Customers concluded that EPGI and EPTI should be awarded a return on equity 25 basis points higher than TransAlta, or 8.5%. This would be equivalent to assuming that EPGI/EPTI is 60% as risky as the market as a whole, using the equity risk premium test with a 50 basis point cushion.

As an alternative, the FIRM Customers submitted that, if the Board were to adopt a significantly higher return for TransAlta than recommended by Drs. Waters and Winter, EPGI/EPTI would be adequately compensated at the same rate of return as TransAlta. The FIRM Customers considered that this would be consistent with previous Board Decisions.

In reply, the FIRM Customers submitted that TransAlta's case for ATWACC was extremely weak and the inflated risk premiums presented by both TAU and EPGI/EPTI should not be given any credence.

The FIRM Customers submitted that the Board should not make an award based on a 50-50 split between the Utility and intervenor. The FIRM Customers stated that the Utilities were well above the Board's last adopted position, whereas the intervenors were below it, though by a much smaller amount. The FIRM Customers noted that they and the COCI agreed that following the method adopted in the last GTA with the current forecast of interest rates would yield a return on equity of 9.125%. The FIRM Customers submitted that TransAlta and EPGI choose to

ignore this approach in an attempt to gain risk premiums for Utility stocks in the range of 550 basis points.

The FIRM Customers noted that, in these proceedings, Dr. Kolbe advocated ATWACC and an equivalent equity risk premium for TransAlta of 550 basis points. However working for the staff of a regulatory Board, Dr. Kolbe used a traditional approach with a risk premium of only 300-350 basis points, similar to, or slightly less than, what the Board adopted in the last GTA.

The FIRM Customers submitted that the 100 basis point adder proposed by EPGI/EPTI to yield a 110–120% market-to-book ratio was excessive. The FIRM Customers noted that the Board previously adopted cushions or flotation adjustments considerably below this amount.

Position of ENMAX

As a member of the COCI, ENMAX adopted the argument filed by them. ENMAX submitted that the Board should give no consideration to providing additional returns on specific assets such as Rossdale and Clover Bar.

In reply argument, ENMAX stated it was "surprised" at the reliance that EPGI placed on the CCES Report prepared by Dr. Waters in its argument. ENMAX considered that, if this 1996 report was reasonable, the 8% to 8.25% on common equity recommendation should also be considered in a similar manner.

ENMAX also disagreed with EPGI's request in argument for a "station by station consideration of revenue requirement." ENMAX noted that there are specific aspects of the EU Act that result in a decrease in the risk of the return to generation assets. Since the risk under the EU Act is potentially less than the existing risk with respect to generation, ENMAX submitted that there was no need to examine revenue requirements on a station by station basis. ENMAX further submitted that the analysis by EPGI only focused on one aspect of the risk on a station by station basis. EPGI failed to recognize that recovery of capital is not applicable to certain of the stations because the capital has been completely or significantly recovered.

ENMAX submitted that the adoption of the minimum return margin method would increase EPGI's return on common equity to 11.38% for 1999, and 11.22% for the year 2000, both in excess of the rate approved by the Board in Decision U97065. With respect to interest coverage, ENMAX noted that DBRS stated EPGI's coverage ratios were hurt by a technicality due to the lack of corporate income tax. DBRS also indicated that EPCOR has a potential competitive advantage because it can potentially offer its customers lower rates through its' current tax status. ENMAX also noted that EPGI and EPTI's interest coverage were low as a result of their embedded cost of debt being higher than a fair rate of return on common equity in today's market.

ENMAX considered that EPGI challenged Drs. Waters and Winter's evidence that risk premium shrink as bond yields decline but provided no definitive analysis of their own. ENMAX noted

that the BCUC, in Exhibit 167 stated that it did not believe reflection of an inverse relationship between interest rates and the equity risk premium in the formula is warranted at this time.

ENMAX concluded that EPGI had misinterpreted the evidence with respect to NLP and PNG. In the case of NLP, Exhibit 162, at pages 110 and 111 did not indicate that investors sold off debt securities in NLP nor did Exhibit 39 at page 17 indicate that investors sold off debt. Both references indicated that the issue in November 1998 was at a yield comparable to other A rated public utilities at the time. With respect to PNG, Exhibit 167 at page 32 and following shows that comparing the three companies on the basis that they all have a B++ rating is simplistic, and does not consider all of the relevant differences in business and financial risk between PNG, EPGI and EPTI.

Position of EAL

EAL agreed with and supported the conclusions and recommendations of Dr. Waters and Dr. Winter, as a joint sponsor of their evidence. EAL agreed with and supported the written argument of the COCI.

Position of LE/RD

LE/RD participated in and supported the evidence and argument of the COCI. As such, LE/RD did not propose to add to the COCI's argument.

LE/RD noted that TransAlta's proposed ATWACC method did not appear to have application to regulated utilities. Furthermore, LE/RD noted that the bond rating companies, which rate the utility and which are an important aspect of the risk evaluation of this utility, do not use the ATWACC method. It appeared to LE/RD that ATWACC was proposed because of the movement to deregulation and the difficulties of determining separate returns and capital structure by business unit. LE/RD submitted that it would be inappropriate to adopt a new model that had little support for the last two years of the traditional regulation of this utility. LE/RD noted that Dr. Evans specifically did not support the ATWACC method.[460] LE/RD acknowledged that ATWACC was appropriate for an unregulated industry but TransAlta is not an unregulated company for the purpose of this application. LE/RD further acknowledged that the ATWACC model is a market-based model but it requires, at the very least, adjustment for embedded debt and capital structure. LE/RD concluded that ATWACC represented a hybrid of market and embedded calculations which may reduces its value as a market based method. LE/RD noted that ATWACC results in an increase in the effective risk premium for TransAlta from the 1996 decision award of 325-375 basis points to a calculated premium of 550 basis points[461]. In the absence of a clearly significant increase in risk over the test period this appeared to LE/RD to be an excessive return. LE/RD therefore submit that there is no good reason to adopt the method for determination of the appropriate return over the two-year test period.

[460] Tr. page 5021
[461] Tr. page 5106

LE/RD disagreed with Dr. Evans' recommendation that EPGI be awarded an additional return based on the requirements for a minimum return margin with respect to the Rossdale and Clover Bar units operated by EPGI. LE/RD noted this increased the recommended rate of return from 11.0 % to 11.38 % for 1999 and 11.21% for 2000. The minimum return margin appeared to LE/RD to be designed to protect the utility against the risk that revenues might be insufficient to pay cash expenses. LE/RD considered that this was not an overall utility risk, but only a risk with respect to a particular unit or units. LE/RD submitted that, for the test years 1999-2000, recovery of costs is not on a unit basis. LE/RD concluded that the proposal to recover a portion of return based on a minimum return margin is premature and the Board should reject use of the minimum return margin for the purpose of calculating the necessary return on equity for EPGI for the test years 1999-2000.

Position of IPPSA/SPPA

IPPSA and SPPA submitted that the implementation of deferral accounts reduced the level of risk to the utilities and should result in a corresponding reduction in their rate of return.[462]

Board Findings

The Board considers that it has accounted for the business and financial risk and income tax differences of the two Utilities and their operating divisions in the preceding section on business risk in this Decision. The Board has also accounted for the risk alteration of deferral accounts in the business risk section of this Decision. Having taken these differences into account, the Board is confident that it would be appropriate to set a rate of return on equity for an integrated utility and account for these factors through the capital structure. In reaching its conclusion on the appropriate rate of return on common equity for the test years 1999 and 2000, the Board has considered the evidence of the five expert witnesses and the results of the techniques they used to reach their conclusions, namely, the comparable earnings, DCF, equity risk premium and ATWACC methods. The Board has evaluated the ATWACC method in the previous section of this Decision. The Board takes note of its findings on ATWACC and parties' assessment of that evidence in argument and reply.

With respect to comparable earnings, the Board notes that the expert witnesses, with the exception of EPGI/EPTI's witness, did not perform a comparable earnings test. EPGI/EPTI's witness gave his comparable earnings test a weight of almost 50%. In the Board's view, the comparable earnings test is sensitive to accounting practices of the sample firms, the sample selection, the selected business cycle and discontinuities caused by mergers, divestitures or restructuring. Given the historical corporate restructuring and economic uncertainty, which may adversely affect the test results, the Board gives little weight to the comparable earnings test in this proceeding for the purposes of determining an appropriate rate of return. The Board, however, considers the results obtained by the comparable earnings test to be a check on the reasonability of the market-based tests.

[462] IPPSA/SPPA Argument, page 45

With respect to DCF results, only witnesses for TransAlta and EPGI/EPTI performed DCF tests in support of their final recommendations. The Board notes that both these witnesses expressed doubts about the validity of the growth component of the DCF model and the volatility of the growth series studied. Notwithstanding the fact that this effect may be adjusted for by judgement, the Board considers the DCF tests should also be assigned little weight in this proceeding. The Board will use the experts' DCF results as a reasonableness test of its final conclusion on rate of ROE.

The five expert witnesses all performed equity risk premium tests in support of their final recommendations. The two Intervenors' witnesses only performed an equity risk premium test in arriving at final conclusions, implicitly weighting this test at 100%. The Utilities' witnesses assigned their equity risk premium results weighting in the order of 50-100%. The Board also has given primary weight to the results of this test. The experts presenting conventional risk premium tests based their evidence on risk-free rates of 5.5-6.0%. Based on the evidence presented, the Board is of the view that the appropriate risk-free rate based on long Canada bonds to be used for this proceeding is in the range of 5.75%. This rate is based on the data available at the time of the hearing, the recommendations of the witnesses' either initial or revised recommendations and the need to set a rate of return on a going-forward basis.

In arriving at estimates of market risk premiums, the expert witnesses either took note of U.S. equity risk premiums or directly weighted U.S. data in their results. The Board exercises its caution in the use of U.S. equity risk premium data for companies whose operations are largely confined to Canada and whose equity financing on foreign capital markets is nil or insignificant compared to the equity financing carried out in Canada. The Board acknowledges the evidence it received in these proceedings that capital markets are becoming globalized. However, it accepts this in the sense that Canadian markets themselves reflect global trends. Furthermore, there are sufficient differences in fiscal and monetary policies between countries not in economic union that the Board does not accept a mechanical weighting of foreign data with Canadian data. The Board does take note of the foreign data as placing certain bounds on the results obtained from Canadian capital markets.

The Board notes that the risk free rate is some 200 basis points lower than the risk free rate in 1996. The Board is persuaded that the historical data relating the market equity risk premium to the risk free rate does not indicate that there exists a significant variation in risk premium over the range of interest rates experienced since 1996. For the purposes of this Decision, the Board is not persuaded that it should reflect any inverse relationship between interest rates and the equity risk premium that may or may not exist when the risk free rate drops from 7.75% to 5.75%.

The risk premiums estimated by the five expert witnesses fall in the range of 225-550 basis points. As noted in its findings in the previous sections of this Decision, the Board considers that the two Utilities and their witnesses have overestimated the Utilities' risk as a result of the restructured electric industry and, therefore, underestimated the downward adjustment from

market that should be applied to the risk premium of the two Utilities. The experts agree that an upward adjustment to the risk premium is necessary for flotation costs and financial flexibility, although the size of the adjustment is in dispute. The Board considers that these are legitimate costs that should be recovered from customers on an on-going basis. The annual cost for flotation and flexibility is certainly less than the maximum of 120 basis points recommended by EPGI/EPTI's witness and probably somewhat above the 25-50 basis point range recommended by the COCI's witnesses. Based on the evidence of the expert witnesses and the evidence on risk premium variance, the Board considers that there is insufficient reason to change its findings of Decision U97065. An equity risk premium in the range of 325-375 basis points, inclusive of all adjustments, is appropriate for the Utilities in 1999 and 2000. On the basis of the foregoing, the Board notes that the mid-point of the indicated range for equity rate of return would be in the range of 9.00-9.50%. Accordingly, the Board considers that an equity rate of return of 9.00-9.50% for the test years 1999 and 2000 is appropriate for each of the Utilities. The Board considers that this rate is commensurate with rates of return earned by enterprises of similar risk. The Board considers the above equity rate of return award will maintain the Utilities' financial integrity and allow them to continue attracting capital on favourable terms.

The following table summarizes the Board's findings respecting equity rate of return:

Equity Rate of Return (1999-2000) – Board Approved	
Risk free rate	5.75%
Equity risk premium	3.25%-3.75%
Equity rate of return	9.00%-9.50%
Equity rate of return (mid-point)	9.25%

(5) Integrated Utility Fair Return

This section summarizes and concludes the Board's findings on the fair return for an integrated utility. The Board's specific determinations in this section apply to the integrated operations of TransAlta. The Board will deal with EPGI under the GENCO fair return section and with EPTI under the TRANSCO fair return section which follow.

It should be noted that rate base numbers and cost rates for debt and preferred used for analysis in these sections are as submitted by the Applicants and are for illustrative purposes only. The allowed rate base numbers and cost rates will be determined after the refilings, reflecting the Board's findings in this Decision.

The Board earlier in this Decision set out its approach to the determination of a fair return. The Board noted that it will use both the traditional method and a modified ATWACC as tools to arrive at the fair return for EPGI, EPTI and TransAlta, with primary weight placed on the traditional method. The Board also noted that since EPGI and EPTI do not pay income tax, the modified ATWACC model collapses to the traditional method used to determine the fair return.

Or in other words, the ATWACC return grossed up by dividing by one minus the tax rate is mathematically equivalent to the traditional fair return plus income tax payable on the equity portion of the fair return.

For the purposes of this section, the Board will use the acronym $ATWACC_{BV}$ to refer to the modified ATWACC which is weighted based on book values for debt, preferred equity and common equity to distinguish it from the ATWACC proposed by TransAlta. The ATWACC proposed by TransAlta will be referred to using the acronym $ATWACC_{MV}$ to note the fact that it is weighted by market values for debt, preferred equity and common equity. The Board will also use the term $ATWACC_{BV}$ (current) or $ATWACC_{MV}$ (current) to refer to an ATWACC based on the current cost rate for debt and equity and the term $ATWACC_{BV}$ (embedded) or $ATWACC_{MV}$ (embedded) to refer to an ATWACC based on the embedded cost rates for debt and equity.

The Board, in the previous business risk, capital structure and equity return sections of this Decision made the following primary determinations respecting the parameters used to arrive at a fair return using the traditional method:

- The Board determined that a range of 40%-42% (midpoint 41%) is an acceptable range of common equity capital structure ratios consistent with the business risks of the integrated company in 1999 and 2000.
- The Board determined that 9.0% to 9.5% (midpoint 9.25%) is an acceptable range for the common equity rate of return using standard tests.

The Board, in the previous ATWACC section of this Decision, determined an ATWACC appropriate for an integrated utility, based on Dr. Vilbert's sample Canadian and U.S. companies. The Board made the following primary adjustments to the $ATWACC_{MV}$ proposed by TransAlta:

- The Board adjusted the proposed $ATWACC_{MV}$ downward by using book rather than market capitalization weightings in order to maintain the longstanding regulatory practice that fair return should be based on the book value (i.e. original cost) of the assets. The Board also found it unlikely that book ratios would have been significantly distorted by unregulated activities whereas market weighted ratios have the potential to be distorted by unregulated activities. The Board concluded that the above adjustment from market weighted capitalization ratios to book weighted capitalization ratios also purged out any effects of unregulated activities. The use of book weightings resulted in a 50 basis point reduction in the proposed $ATWACC_{MV}$
- The Board ensured that the market equity rate of return used in the ATWACC build up was consistent with the Board's determination of the appropriate market based equity rate of return range of 9.0% to 9.5%. This resulted in a further 25 basis point reduction in the proposed $ATWACC_{MV}$.

3. GENCO/TRANSCO/DISCO
(i) Return

The final conclusion in the ATWACC section was that the proposed $ATWACC_{MV}$ (current) of 6.91% should be reduced by some 75 basis points to reflect the combination of the above-noted adjustments to arrive at an $ATWACC_{BV}$ (current) of 6.16% (i.e. 6.91%-0.75%).

The task before the Board in this section is to make a final determination on the fair return to be awarded for the test years 1999 and 2000 by placing an appropriate weight on the results of the traditional return analysis and the ATWACC analysis. The Board also noted earlier in this Decision that whatever method is used, the focus should be on determining a fair return and not necessarily on the tools used to arrive at the fair return. The Board has previously determined that it will place primary emphasis on the traditional method.

The Board considers it important to note at the outset that the common equity ratio and equity rate of return used in the determination of a fair return and income tax are for the purposes of establishing the revenue requirement required to fix just and reasonable tariffs. The common equity ratio used for rate-making purposes does not necessarily dictate the capital structure that must be followed by the regulated utility.

As a first step in making a final determination, the Board, in Appendices 2 and 3, has determined the $ATWACC_{BV}$ that would produce the same fair return and income tax that the traditional method would produce using the parameters at the mid-point of the range for the common equity ratio and common equity rate of return.

An examination of these results shows that the resulting $ATWACC_{BV}$ (current) is 6.18% for 1999 and 6.17% for 2000 compared to the independent $ATWACC_{BV}$ (current) analysis results referred to above of 6.16% (Appendix 1, p.14). The Board concludes that these differences are not material and that a properly calibrated ATWACC produces fair return plus income tax results that are identical to the results of the traditional method. The Board considers that an $ATWACC_{BV}$ (current) determined from the mid-point of the traditional method ensures that there is no discrepancy, however small, between the two results. Accordingly, the Board will use the $ATWACC_{BV}$ (current) that falls out of the mid-point of the traditional return parameters.

The following table summarizes the results of the traditional and ATWACC analysis for TransAlta's integrated utility operation:

3. GENCO/TRANSCO/DISCO
(i) Return

TransAlta-Integrated
Traditional vs. $ATWACC_{BV}$ Comparison

	1999	1999	2000	2000
Traditional Method	**Range**	**Mid-Point**	**Range**	**Mid-Point**
Common Equity Ratio	40%-42%	41%	40%-42%	41%
Equity Rate of Return	9.0%-9.5%	9.25%	9.0%-9.5%	9.25%
Before Tax Int. Coverage	3.29-3.39	3.34	3.47-3.58	3.52
After Tax Int. Coverage	2.11-2.16	2.13	2.15-2.20	2.17
ATWACC Method				
$ATWACC_{BV}$ (current)	6.18%	6.18%	6.17%	6.17%
$ATWACC_{BV}$ (embedded)	6.84%	6.84%	6.67%	6.67%
Before Tax Int. Coverage	3.29-3.39	3.34	3.47-3.58	3.52
After Tax Int. Coverage	2.11-2.16	2.13	2.15-2.20	2.17

Next, the Board used the above ATWACC results to assess the change to the equity rate of return that would be required to maintain the same fair return and income tax over the range of acceptable common equity ratios. The results of this exercise are summarized in the following table:

TransAlta-Integrated
Board Approved Fair Return and Income Tax

	1999		
Traditional Method			
Common Equity Ratio	40%	41%	42%
Equity Rate of Return	9.40%	9.25%	9.11%
Fair Return	$248.2 million	$247.5 million	$246.7 million
Income Tax*	$100.4 million	$101.1 million	$101.9 million
Fair Return & Tax*	$348.6 million	$348.6 million	$348.6 million
ATWACC Method			
$ATWACC_{BV}$ (current)	6.18%	6.18%	6.18%
$ATWACC_{BV}$ (embedded)	6.84%	6.84%	6.84%
Fair Return & Tax*	$348.6 million	$348.6 million	$348.6 million

*Book Income tax only. Does not include tax adjustments.

TransAlta-Integrated
Board Approved Fair Return and Income Tax

2000			
Traditional Method			
Common Equity Ratio	40%	41%	42%
Equity Rate of Return	9.40%	9.25%	9.11%
Fair Return	$237.4 million	$236.6 million	$235.9 million
Income Tax*	$97.6 million	$98.4 million	$99.1 million
Fair Return & Tax*	$335.0 million	$335.0 million	$335.0 million
ATWACC Method			
$ATWACC_{BV}$ (current)	6.17%	6.17%	6.17%
$ATWACC_{BV}$ (embedded)	6.67%	6.67%	6.67%
Fair Return & Tax*	$335.0 million	$335.0 million	$335.0 million

*Book income tax only. Does not include tax adjustments.

The Board is satisfied that all of the above results fall within the range of common equity ratios and equity rates of return determined by the Board using the traditional method. The Board considers that the $ATWACC_{BV}$ model is a useful tool to ensure that the relationship between common equity ratio and equity rate of return is adjusted appropriately to arrive at the same allowed fair return and income tax components of the integrated utility revenue requirement for rate-making purposes.

The Board considers it appropriate for management to retain the flexibility to determine actual capital structure within the narrow range. Accordingly, the Board considers that it is unnecessary for the Board to make a specific point determination of the common equity ratio and equity rate of return as long as the combination of the two parameters is consistent with an $ATWACC_{BV}$ (current) of 6.18% in 1999 and 6.17% in 2000.

The Board noted earlier that if it used the ATWACC method in any fashion, it is extremely important for the Utilities to communicate the results of the determination of the fair return using both the traditional and ATWACC methods, in order that all parties clearly understand the numerical relationships between the two methods.

The Board notes that any combination of common equity ratio and equity rate of return that produces the allowed $ATWACC_{BV}$ (embedded) will produce the same fair return and income tax components of the revenue requirement. Consequently, for rate-making purposes, the Board is indifferent to the combination of common equity ratio and equity rate of return. However, the Board considers that, for the purposes of the refiling and ease of communication, all schedules and tables should be prepared using the mid-point of the range determined for the traditional method (i.e., 9.25% ROE on a 41% common equity ratio). The Board considers that TransAlta,

in its refiling, should also demonstrate that the refiling is consistent with an $ATWACC_{BV}$ (current) of 6.18% for 1999 and 6.17% for 2000 and should clearly set out the numerical relationships between the two methods similar to the format used in Appendix 2 and 3.

Accordingly, the Board directs TransAlta, in its refiling, to reflect the following in its integrated utility refiling:

- An integrated common equity ratio of 41%
- An equity rate of return of 9.25%
- An $ATWACC_{BV}$ (current) of 6.18% for 1999 and 6.17% for 2000 adjusted per refiled embedded cost rates
- Ensure that the refiled fair return and income tax for the integrated utility reconciles with the sum of the refiled fair return and income tax of the business functions. The integrated common equity ratio may be adjusted slightly, if necessary, to achieve this reconciliation.

The Board considers that further useful insights and assistance can be obtained from the principles of the ATWACC model that will assist it in determining the fair return by business function. The Board will now set out its findings respecting the fair return by business function.

(6) GENCO Fair Return

This section summarizes and concludes the Board's findings on the fair return for the GENCO business function. The Board will deal specifically with the GENCO operations of TransAlta and EPGI in the following sub-sections.

(A) TransAlta GENCO

The Board, in the previous business risk, capital structure and equity return sections of this Decision, made the following primary determinations respecting the parameters used to arrive at a fair return for GENCO operations using the traditional method:

- The Board determined that a differential of approximately negative 100 basis points (1%) in the common equity ratio would be appropriate compared to integrated utility operations. Accordingly, the Board determined that a range of 39%-41% (midpoint 40%) is an acceptable range of common equity capital structure ratios consistent with the business risks of an investor-owned GENCO in 1999 and 2000.
- The Board determined that 9.0% to 9.5% (midpoint 9.25%) is an acceptable range for the common equity rate of return using standard tests.

The Board, in the previous ATWACC section of this Decision, determined an ATWACC, appropriate for the GENCO function. The Board noted that Dr. Kolbe suggested that an

3. GENCO/TRANSCO/DISCO
(i) Return

$ATWACC_{MV}$ (current) of 6.75% would be appropriate considering a long-term view whereas an $ATWACC_{MV}$ (current) of 7.00% would be appropriate if the focus was solely based on the short-term test periods. Applying the Board's adjustment of 0.75% to these recommendations resulted in a range of 6.00% to 6.25% for an $ATWACC_{BV}$ (current) which the Board considers to be appropriate.

Again as a first step in making a final determination, the Board, in Appendix 2 and 3, has determined the $ATWACC_{BV}$ that would produce the same fair return and income tax that the traditional method would produce using the parameters at the mid-point of the range for the common equity ratio and common equity rate of return.

An examination of these results shows that the resulting $ATWACC_{BV}$ (current) is 6.12% for 1999 and 6.11% for 2000, compared to the independent $ATWACC_{BV}$ (current) analysis results of 6.125% (the mid-point of 6.00%-6.25%). The Board concludes that the $ATWACC_{BV}$ (embedded) produces the same results as the traditional method.

The following table summarizes the results of the traditional and ATWACC analysis for TransAlta's GENCO operations:

TransAlta–GENCO
Traditional vs. $ATWACC_{BV}$ Comparison

TransAlta GENCO	1999	1999	2000	2000
Traditional Method	**Range**	**Mid-Point**	**Range**	**Mid-Point**
Common Equity Ratio	39%-41%	40%	39%-41%	40%
Equity Rate of Return	9.0%-9.5%	9.25%	9.0%-9.5%	9.25%
Before Tax Int. Coverage	3.11-3.20	3.15	3.24-3.34	3.29
After Tax Int. Coverage	2.06-2.11	2.09	2.10-2.15	2.13
ATWACC Method				
$ATWACC_{BV}$ (current)	6.12%	6.12%	6.11%	6.11%
$ATWACC_{BV}$ (embedded)	6.80%	6.80%	6.62%	6.62%
Before Tax Int. Coverage	3.11-3.20	3.15	3.24-3.34	3.29
After Tax Int. Coverage	2.06-2.11	2.09	2.10-2.15	2.13

Next the Board used the above ATWACC results to assess the change to the equity rate of return that would be required to maintain the same fair return and income tax over the range of the common equity ratio. The results are summarized in the following table:

3. GENCO/TRANSCO/DISCO
(i) Return

TransAlta–GENCO
Board Approved Fair Return and Income Tax

1999			
Traditional Method			
Common Equity Ratio	39%	40%	41%
Equity Rate of Return	9.40%	9.25%	9.11%
Fair Return	$153.7 million	$153.3 million	$152.8 million
Income Tax*	$61.0 million	$61.4 million	$61.9 million
Fair Return & Tax*	$214.7 million	$214.7 million	$214.7 million
ATWACC Method			
$ATWACC_{BV}$ (current)	6.12%	6.12%	6.12%
$ATWACC_{BV}$ (embedded)	6.80%	6.80%	6.80%
Fair Return & Tax*	$214.7 million	$214.7 million	$214.7 million

*Book income tax only. Does not include tax adjustments.

TransAlta–GENCO
Board Approved Fair Return and Income Tax

2000			
Traditional Method			
Common Equity Ratio	39%	40%	41%
Equity Rate of Return	9.40%	9.25%	9.11%
Fair Return	$147.4 million	$147.0 million	$146.5 million
Income Tax*	$59.5 million	$59.9 million	$60.4 million
Fair Return & Tax*	$206.9 million	$206.9 million	$206.9 million
ATWACC Method			
$ATWACC_{BV}$ (current)	6.11%	6.11%	6.11%
$ATWACC_{BV}$ (embedded)	6.62%	6.62%	6.62%
Fair Return & Tax*	$206.9 million	$206.9 million	$206.9 million

*Book income tax only. Does not include tax adjustments.

The Board is satisfied that all of the above results fall within the range of common equity ratios and equity rates of return determined by the Board using the traditional method. The Board considers that the $ATWACC_{BV}$ model is a useful tool to ensure that the relationship between common equity ratios and equity rate of return is adjusted appropriately to arrive at the same allowed fair return and income tax components of the GENCO revenue requirement for rate-making purposes.

3. GENCO/TRANSCO/DISCO
(i) Return

The Board considers it appropriate for management to retain the flexibility to determine actual capital structure within the narrow range. Accordingly, the Board considers that it is unnecessary for the Board to make a specific point determination of the common equity ratio and equity rate of return as long as the combination of the two parameters is consistent with the allowed $ATWACC_{BV}$ (current) of 6.12% in 1999 and 6.11% in 2000.

The Board noted earlier that if it used the ATWACC method, it is extremely important for the Utilities to communicate the results of the determination of the fair return using both the traditional and ATWACC methods, in order that all parties clearly understand the numerical relationships between the two methods.

The Board notes that any combination of common equity ratio and equity rate of return that produces the allowed $ATWACC_{BV}$ (embedded) will produce the same fair return and income tax components of the revenue requirement. Consequently, for rate-making purposes, the Board is indifferent to the combination of common equity ratio and equity rate of return. However, the Board considers that, for the purposes of the refiling and ease of communication, all schedules and tables should be prepared using the mid-point of the range determined for the traditional method (i.e., 9.25% ROE on a 40% common equity ratio). The Board considers that TransAlta-GENCO, in its refiling, should also demonstrate that the refiling is consistent with an allowed $ATWACC_{BV}$ (current) of 6.12% for 1999 and 6.11% for 2000 and should clearly set out the numerical relationships between the two methods similar to the format used in Appendices 2 and 3.

The Board directs TransAlta-GENCO to reflect the following in its refiling:

- A common equity ratio of 40%
- An equity rate of return of 9.25%
- An $ATWACC_{BV}$ (current) of 6.12% for 1999 and 6.11% for 2000 adjusted for refiled embedded cost rates

(B) EPGI

The Board will use the TransAlta-GENCO results as a starting point in its determination of a fair return for EPGI.

The Board notes the evidence of Ms. McLeod on behalf of EPGI/EPTI wherein she stated the following:

> The shareholders of EPTI and EPGI are exposed to greater financial risk than the shareholders of either TransAlta Utilities Corporation ("TransAlta") or Alberta Power Limited ("APL"). This incremental financial risk exposure relates to two factors. First, both TransAlta and APL have a substantial preferred share component to their capital structures which has the effect of reducing the

> proportion of senior debt and increasing interest coverage ratios. In addition, EPTI and EPGI are not currently taxable, with the result that their stand-alone corporate debt interest coverage ratios are relatively very low at the applied-for capital structures and rates of return on common equity.
>
> As a result, EPGI expects to receive a debt rating in the BBB category from CBRS, which falls below the effective minimum standard of financial integrity for Canadian corporate issuers and which is substantially lower than the bond ratings of TransAlta and Canadian Utilities Limited.
>
> I believe it would be impractical at this time to attempt to compensate for these incremental financial risk factors by making a further adjustment to my recommendation with respect to the appropriate common equity ratio for the two companies. However, these factors would tend to lend emphasis to the upper end of the reasonable range for EPGI.[463]

The Board notes the evidence of Dr. Evans that a higher common equity ratio was required "when an income tax 'cushion' is unavailable to support the payment of bond interest." Dr. Evans noted that the common equity ratio could be lowered by some 2.5% if EPGI commenced to pay income tax.[464]

The Board also notes that EPGI's cost of embedded debt is considerably higher than TransAlta-GENCO which results in lower coverage ratios.

Taking all of the above into consideration, the Board considers that EPGI should have a higher common equity ratio than TransAlta-GENCO. The Board considers a differential of 400 basis points (4%) would be appropriate at this time to recognize the higher financial risks for EPGI. The following table compares the Board's findings respecting capital structures for EPGI and TransAlta GENCO.

Board Approved

Capital Structure (GENCO) 1999-2000		
Capital Structure	**TransAlta GENCO**	**EPGI**
Debt Ratio	50.5%	56.0%
Preferred Equity Ratio	9.5%	0.0%
Common Equity Ratio	40.0%	44.0%

463 ENMAX.EPGI-22(d)
464 Dr. Evans Evidence p.52

3. GENCO/TRANSCO/DISCO
(i) Return

The following table summarizes the results of the traditional and ATWACC analysis for EPGI's utility operation as set out in Appendix 4 and 5:

EPGI
Traditional vs. ATWACC$_{BV}$ Comparison

EPGI	**1999**	**1999**	**2000**	**2000**
Traditional Method	**Range**	**Mid-Point**	**Range**	**Mid-Point**
Common Equity Ratio	43%-45%	44%	43%-45%	44%
Equity Rate of Return	9.0%-9.5%	9.25%	9.0%-9.5%	9.25%
After Tax Int. Coverage	1.70-1.73	1.72	1.70-1.74	1.72
ATWACC Method				
ATWACC$_{BV}$ (current)	7.41%	7.41%	7.41%	7.41%
ATWACC$_{BV}$ (embedded)	9.75%	9.75%	9.73%	9.73%
After Tax Int. Coverage	1.70-1.73	1.72	1.70-1.74	1.72

The Board notes that with the higher common equity ratio, EPGI's resulting interest coverage ratio at 1.7 will be more comparable to an investor-owned utility's after-tax coverage ratio.

Next, the Board used the above ATWACC results to assess the change to the equity rate of return that would be required to maintain the same fair return and income tax over the range of the common equity ratio. The results are summarized in the following table:

EPGI
Board Approved Fair Return and Income Tax

	1999		
Traditional Method			
Common Equity Ratio	43%	44%	45%
Equity Rate of Return	9.33%	9.25%	9.18%
Fair Return	$123.4 million	$123.4 million	$123.4 million
Income Tax	$0 million	$0 million	$0 million
Fair Return & Tax	$123.4 million	$123.4 million	$123.4 million
ATWACC Method			
ATWACC$_{BV}$ (current)	7.41%	7.41%	7.41%
ATWACC$_{BV}$ (embedded)	9.75%	9.75%	9.75%
Fair Return & Tax	$123.4 million	$123.4 million	$123.4 million

3. GENCO/TRANSCO/DISCO
(i) Return

EPGI
Board Approved Fair Return and Income Tax

2000			
Traditional Method			
Common Equity Ratio	43%	44%	45%
Equity Rate of Return	9.33%	9.25%	9.18%
Fair Return	$120.8 million	$120.8 million	$120.8 million
Income Tax	$0 million	$0 million	$0 million
Fair Return & Tax	$120.8 million	$120.8 million	$120.8 million
ATWACC Method			
$ATWACC_{BV}$ (current)	7.41%	7.41%	7.41%
$ATWACC_{BV}$ (embedded)	9.73%	9.73%	9.73%
Fair Return & Tax	$120.8 million	$120.8 million	$120.8 million

The Board is satisfied that all of the above results fall within the range of common equity ratios and equity rates of return determined by the Board using the traditional method. The Board considers that the $ATWACC_{BV}$ model is a useful tool to ensure that the relationship between common equity ratios and equity rate of return is adjusted appropriately to arrive at the same allowed fair return and income tax components of the GENCO revenue requirement for rate-making purposes.

The Board considers it appropriate for management to retain the flexibility to determine actual capital structure within the narrow range. Accordingly, the Board considers that it is unnecessary for the Board to make a specific point determination of the common equity ratio and equity rate of return as long as the combination of the two parameters is consistent with an $ATWACC_{BV}$ (current) ATWACC of 7.41% in 1999 and 7.41% in 2000.

The Board noted earlier that if it used the ATWACC method, it is extremely important for the Utilities to communicate the results of the determination of the fair return using both the traditional and ATWACC methods, in order that all parties clearly understand the numerical relationships between the two methods.

The Board notes that any combination of common equity ratio and equity rate of return that produces the allowed $ATWACC_{BV}$ (embedded) will produce the same fair return for EPGI's revenue requirement. Consequently, for rate-making purposes, the Board is indifferent to the combination of common equity ratio and equity rate of return. However, the Board considers that, for the purposes of the refiling and ease of communication, all schedules and tables should be prepared using the mid-point of the range determined for the traditional method (i.e., 9.25% ROE on a 44% common equity ratio). The Board considers that EPGI, in its refiling, should also demonstrate that the refiling is consistent with an allowed $ATWACC_{BV}$ (current) of 7.41% for

1999 and 7.41% for 2000 and should clearly set out the numerical relationships between the two methods similar to the format used in Appendices 4 and 5.

The Board directs EPGI to reflect the following in its refiling:

- A common equity ratio of 44%
- An equity rate of return of 9.25%
- An $ATWACC_{BV}$ (current) of 7.41% for 1999 and 7.41% for 2000 adjusted per refiled embedded cost rates

(7) TRANSCO Fair Return

This section summarizes and concludes the Board's findings on the fair return for the TRANSCO business function. The Board will deal specifically with the TRANSCO operations of TransAlta and EPTI in the following sub-sections.

(A) TransAlta TRANSCO

The Board, in the previous business risk, capital structure and equity return sections of this Decision made the following primary determinations respecting the parameters used to arrive at a fair return for TRANSCO operations using the traditional method:

- The Board determined that a differential of approximately negative 600 basis points (6%) in the common equity ratio would be appropriate compared to integrated utility operations. Accordingly, the Board determined that a range of 34%-36% (midpoint 35%) is an acceptable range of common equity capital structure ratios consistent with the business risks of an investor-owned TRANSCO in 1999 and 2000.
- The Board determined that 9.0% to 9.5% (midpoint 9.25%) is an acceptable range for the common equity rate of return using standard tests.

The Board, in the previous ATWACC section of this Decision, determined an ATWACC appropriate for the TRANSCO function. The Board noted that Dr. Kolbe suggested that an $ATWACC_{MV}$ (current) of 6.25% would be appropriate considering a long-term view. The Board noted that if the focus was solely based on the short-term test periods, the differential on transmission would have to offset Dr. Kolbe's 50 basis point differential on distribution. Using the rate base weightings for transmission (23%) and distribution (15%) would produce a transmission differential of 33 basis points or an $ATWACC_{MV}$ (current) of approximately 6.67% (i.e. 7.00%-0.33%). Applying the Board's adjustment of 0.75% to these recommendations resulted in a range of 5.50% to 5.92% for an $ATWACC_{BV}$ (current) which the Board considers to be appropriate.

3. GENCO/TRANSCO/DISCO
(i) Return

Again as a first step in making a final determination, the Board, in Appendix 2 and 3, has determined the $ATWACC_{BV}$ (embedded) that would produce the same fair return and income tax that the traditional method would produce using the parameters at the mid-point of the range for the common equity ratio and common equity rate of return.

An examination of these results shows that the resulting $ATWACC_{BV}$ (current) is 5.83% for 1999 and 5.82% for 2000, compared to the independent $ATWACC_{BV}$ (current) analysis range of 5.50%-5.92%. The Board concludes that the $ATWACC_{BV}$ (embedded) produces the same results as the traditional method.

The following table summarizes the results of the traditional and ATWACC analysis for TransAlta's TRANSCO operations:

TransAlta–TRANSCO
Traditional vs. $ATWACC_{BV}$ Comparison

TransAlta TRANSCO	**1999**	**1999**	**2000**	**2000**
Traditional Method	**Range**	**Mid-Point**	**Range**	**Mid-Point**
Common Equity Ratio	34%-36%	35%	34%-36%	35%
Equity Rate of Return	9.0%-9.5%	9.25%	9.0%-9.5%	9.25%
Before Tax Int. Coverage	2.79-2.87	2.83	2.88-2.96	2.92
After Tax Int. Coverage	1.87-1.91	1.89	1.90-1.94	1.92
ATWACC Method				
$ATWACC_{BV}$ (current)	5.83%	5.83%	5.82%	5.82%
$ATWACC_{BV}$ (embedded)	6.56%	6.56%	6.38%	6.38%
Before Tax Int. Coverage	2.79-2.87	2.83	2.88-2.96	2.92
After Tax Int. Coverage	1.87-1.91	1.89	1.90-1.94	1.92

The Board next used the above ATWACC results to assess the change to the equity rate of return that would be required to maintain the same fair return and income tax over the range of the common equity ratio. The results are summarized in the following table:

TransAlta–TRANSCO
Board Approved Fair Return and Income Tax

1999			
Traditional Method			
Common Equity Ratio	34%	35%	36%
Equity Rate of Return	9.42%	9.25%	9.09%
Fair Return	\$56.9 million	\$56.7 million	\$56.5 million
Income Tax*	\$20.3 million	\$20.5 million	\$20.7 million
Fair Return & Tax*	\$77.2 million	\$77.2 million	\$77.2 million
ATWACC Method			
$ATWACC_{BV}$ (current)	5.83%	5.83%	5.83%
$ATWACC_{BV}$ (embedded)	6.56%	6.56%	6.56%
Fair Return & Tax*	\$77.2 million	\$77.2 million	\$77.2 million

*Book income tax only. Does not include tax adjustments.

TransAlta–TRANSCO
Board Approved Fair Return and Income Tax

2000			
Traditional Method			
Common Equity Ratio	34%	35%	36%
Equity Rate of Return	9.42%	9.25%	9.09%
Fair Return	\$54.7 million	\$54.6 million	\$54.4 million
Income Tax*	\$20.0 million	\$20.1 million	\$20.3 million
Fair Return & Tax*	\$74.7 million	\$74.7 million	\$74.7 million
ATWACC Method			
$ATWACC_{BV}$ (current	5.82%	5.82%	5.82%
$ATWACC_{BV}$ (embedded)	6.38%	6.38%	6.38%
Fair Return & Tax*	\$74.7 million	\$74.7 million	\$74.7 million

*Book income tax only. Does not include tax adjustments.

The Board is satisfied that all of the above results fall within the range of common equity ratios and equity rates of return determined by the Board using the traditional method. The Board considers that the $ATWACC_{BV}$ model is a useful tool to ensure that the relationship between common equity ratios and equity rate of return is adjusted appropriately to arrive at the same allowed fair return and income tax components of the TRANSCO revenue requirement for rate-making purposes.

The Board considers it appropriate for management to retain the flexibility to determine actual capital structure within the narrow range. Accordingly, the Board considers that it is unnecessary for the Board to make a specific point determination of the common equity ratio and equity rate of return as long as the combination of the two parameters is consistent with an $ATWACC_{BV}$ (current) of 5.83% in 1999 and 5.82% in 2000.

The Board noted earlier that if it used the ATWACC method, it is extremely important for the Utilities to communicate the results of the determination of the fair return using both the traditional and ATWACC methods so that all parties clearly understand the numerical relationships between the two methods.

The Board notes that any combination of common equity ratio and equity rate of return that produces the allowed $ATWACC_{BV}$ (embedded) will produce the same fair return and income tax components of the revenue requirement. Consequently for rate-making purposes, the Board is indifferent to the combination of common equity ratio and equity rate of return . However, the Board considers that, for the purposes of the refiling and ease of communication, all schedules and tables should be prepared using the mid-point of the range determined for the traditional method (i.e., 9.25% ROE on a 35% common equity ratio). The Board considers that TransAlta-TRANSCO, in its refiling, should also demonstrate that the refiling is consistent with an allowed $ATWACC_{BV}$ (current) of 5.83% for 1999 and 5.82% for 2000 and should clearly set out the numerical relationships between the two methods similar to the format used in Appendix 2 and 3.

The Board directs TransAlta-TRANSCO to reflect the following in its refiling:

- A common equity ratio of 35%
- An equity rate of return of 9.25%
- An $ATWACC_{BV}$ (current) of 5.83% for 1999 and 5.82% for 2000 adjusted per refiled embedded cost rates

(B) EPTI

The Board notes that EPGI/EPTI requested a differential of 1100-1500 basis points (11-15%) in the common equity ratio between EPGI at 46%-49% and EPTI at 34%-35%. If the Board were to maintain the requested 1100-1500 basis point differential from the Board's findings respecting EPGI, this would suggest a common equity ratio of 29%-33% for EPTI (i.e. EPGI at 44% minus 11%-15%). The Board notes the evidence of Ms McLeod on behalf of EPTI wherein she stated the following:

> In my opinion, the business risks of the transmission function within the Alberta electric industry are comparable to those of the major Canadian natural gas transmission, gathering and distribution companies. Consequently, I believe that a capital structure including approximately a 35.0% common equity is appropriate

for EPTI. The forecast actual common equity ratio of EPTI of 35.2% for 1999 and 34.1% for 2000 is consistent with this recommendation.[465]

The Board notes the evidence of Ms. McLeod that "because of its size, EPTI will not be seeking a formal debt rating."[466]

Taking all of the above into consideration, the Board accepts the recommendation of Ms. McLeod and notes that a common equity ratio of 35% is also consistent with the Board's award for TransAlta-TRANSCO. Accordingly the Board considers that EPTI's request is reasonable and will use a range of 34% to 36%.

The following table summarizes the results of the traditional and ATWACC analysis for EPTI:

EPTI
Traditional vs. ATWACC$_{BV}$ Comparison

EPTI	1999	1999	2000	2000
Traditional Method	**Range**	**Mid-Point**	**Range**	**Mid-Point**
Common Equity Ratio	34%-36%	35%	34%-36%	35%
Equity Rate of Return	9.0%-9.5%	9.25%	9.0%-9.5%	9.25%
After Tax Int. Coverage	1.48-1.51	1.50	1.52-1.55	1.53
ATWACC Method				
ATWACC$_{BV}$ (current)	7.11%	7.11%	7.11%	7.11%
ATWACC$_{BV}$ (embedded)	9.75%	9.75%	9.34%	9.34%
After Tax Int. Coverage	1.48-1.51	1.50	1.52-1.55	1.53

Next, the Board used the above ATWACC results to assess the change to the equity rate of return that would be required to maintain the same fair return and income tax over the range of the common equity ratio. The results are summarized in the following table:

465 ENMAX.EPGI-22(d)
466 ENMAX.EPGI-22(d)

EPTI
Board Approved Fair Return and Income Tax

1999			
Traditional Method			
Common Equity Ratio	34%	35%	36%
Equity Rate of Return	9.35%	9.25%	9.16%
Fair Return	$14.7 million	$14.7 million	$14.7 million
Income Tax	$ 0.0 million	$ 0.0 million	$ 0.0 million
Fair Return & Tax	$14.7 million	$14.7 million	$14.7 million
ATWACC Method			
$ATWACC_{BV}$ (current)	7.11%	7.11%	7.11%
$ATWACC_{BV}$ (embedded)	9.75%	9.75%	9.75%
Fair Return & Tax	$14.7 million	$14.7 million	$14.7 million

EPTI
Board Approved Fair Return and Income Tax

2000			
Traditional Method			
Common Equity Ratio	34%	35%	36%
Equity Rate of Return	9.35%	9.25%	9.16%
Fair Return	$14.0 million	$14.0 million	$14.0 million
Income Tax	$ 0.0 million	$ 0.0 million	$ 0.0 million
Fair Return & Tax	$14.0 million	$14.0 million	$14.0 million
ATWACC Method			
$ATWACC_{BV}$ (current)	7.11%	7.11%	7.11%
$ATWACC_{BV}$ (embedded)	9.34%	9.34%	9.34%
Fair Return & Tax	$14.0 million	$14.0 million	$14.0 million

The Board is satisfied that all of the above results fall within the range of common equity ratios and equity rates of return determined by the Board using the traditional method. The Board considers that the $ATWACC_{BV}$ model is a useful tool to ensure that the relationship between common equity ratios and equity rate of return is adjusted appropriately to arrive at the same allowed fair return and income tax components of the TRANSCO revenue requirement for rate-making purposes.

The Board considers it appropriate for management to retain the flexibility to determine actual capital structure within the narrow range. Accordingly, the Board considers that it is unnecessary

for the Board to make a specific point determination of the common equity ratio and equity rate of return as long as the combination of the two parameters is consistent with an $ATWACC_{BV}$ (current) of 7.11% in 1999 and 7.11% in 2000.

The Board noted earlier that if it used the ATWACC method, it is extremely important for the Utilities to communicate the results of the determination of the fair return using both the traditional and ATWACC methods, in order that all parties clearly understand the numerical relationships between the two methods.

The Board notes that any combination of common equity ratio and equity rate of return that produces the allowed $ATWACC_{BV}$ (embedded) will produce the same fair return for EPTI's revenue requirement. Consequently, for rate-making purposes, the Board is indifferent to the combination of common equity ratio and equity rate of return . However, the Board considers that, for the purposes of the refiling and ease of communication, all schedules and tables should be prepared using the mid-point of the range determined for the traditional method (i.e., 9.25% ROE on a 35% common equity ratio). The Board considers that EPTI, in its refiling, should also demonstrate that the refiling is consistent with an allowed $ATWACC_{BV}$ (current) of 7.11% for 1999 and 7.11% for 2000 and should clearly set out the numerical relationships between the two methods similar to the format used in Appendix 4 and 5.

The Board directs EPTI to reflect the following in its refiling:

- A common equity ratio of 35%
- An equity rate of return of 9.25%
- An $ATWACC_{BV}$ (current) of 7.11% in 1999 and 2000 adjusted for refiled embedded cost rates

(8) DISCO Fair Return

This section summarizes and concludes the Board's findings on the fair return for the DISCO business function. Accordingly, the Board's specific determinations in this section apply to the DISCO business function of TransAlta's operations.

The Board, in the previous business risk, capital structure and equity return sections of this Decision made the following primary determinations respecting the parameters used to arrive at a fair return for DISCO operations using the traditional method:

- The Board determined that a differential of approximately positive 1350 basis points (13.5%) in the common equity ratio would be appropriate compared to integrated utility operations. Accordingly, the Board determined that a range of 53.5%-55.5% (midpoint 54.5%) is an acceptable range of common equity capital structure ratios consistent with the business risks of an investor-owned DISCO in 1999 and 2000.

3. GENCO/TRANSCO/DISCO
(i) Return

- The Board has determined that 9.0% to 9.5% (midpoint 9.25%) is an acceptable range for the common equity rate of return using standard tests.

The Board, in the previous ATWACC section of this Decision determined an ATWACC, appropriate for the DISCO function. The Board noted that Dr. Kolbe suggested that an $ATWACC_{MV}$ (current) of 8.00% would be appropriate considering a long-term view whereas an $ATWACC_{MV}$ (current) of 7.50% would be appropriate if the focus was solely based on the short-term test periods. Applying the Board's adjustment of 0.75% to these recommendations resulted in an $ATWACC_{BV}$ (current) range of 6.75% to 7.25% which the Board considers to be appropriate.

Again as a first step in making a final determination, the Board, in Appendix 2 and 3, has determined the $ATWACC_{BV}$ (embedded) that would produce the same fair return and income tax that the traditional method would produce using the parameters at the mid-point of the range for the common equity ratio and common equity rate of return.

An examination of these results shows that the resulting $ATWACC_{BV}$ (current) is 6.97% for 1999 and 6.96% for 2000, compared to the independent $ATWACC_{BV}$ (current) analysis results of 7.00% (i.e., the mid-point of 6.75%-7.25%). The Board concludes that the $ATWACC_{BV}$ produces the same results as the traditional method.

The following table summarizes the results of the traditional and ATWACC analysis for TransAlta's DISCO operations:

TransAlta–DISCO
Traditional vs. $ATWACC_{BV}$ Comparison

TransAlta DISCO	**1999**	**1999**	**2000**	**2000**
Traditional Method	**Range**	**Mid-Point**	**Range**	**Mid-Point**
Common Equity Ratio	53.5%-55.5%	54.5%	53.5%-55.5%	54.5%
Equity Rate of Return	9.0%-9.5%	9.25%	9.0%-9.5%	9.25%
Before Tax Int. Coverage	5.52-5.75	5.64	6.23-6.50	6.36
After Tax Int. Coverage	2.93-3.03	2.98	3.01-3.12	3.06
ATWACC Method				
$ATWACC_{BV}$ (current)	6.97%	6.97%	6.96%	6.96%
$ATWACC_{BV}$ (embedded)	7.46%	7.46%	7.33%	7.33%
Before Tax Int. Coverage	5.52-5.75	5.64	6.23-6.50	6.36
After Tax Int. Coverage	2.93-3.03	2.98	3.01-3.12	3.06

The Board next used the above ATWACC results to assess the change to the equity rate of return that would be required to maintain the same fair return and income tax over the range of the common equity ratio. The results are summarized in the following table:

TransAlta–DISCO
Board Approved Fair Return and Income Tax

1999			
Traditional Method			
Common Equity Ratio	53.5%	54.5%	55.5%
Equity Rate of Return	9.36%	9.25%	9.14%
Fair Return	$37.6 million	$37.5 million	$37.4 million
Income Tax*	$19.1 million	$19.2 million	$19.3 million
Fair Return & Tax*	$56.7 million	$56.7 million	$56.7 million
ATWACC Method			
$ATWACC_{BV}$ (current)	6.97%	6.97%	6.97%
$ATWACC_{BV}$ (embedded)	7.46%	7.46%	7.46%
Fair Return & Tax*	$56.7 million	$56.7 million	$56.7 million

*Book income tax only. Does not include tax adjustments.

TransAlta–DISCO
Board Approved Fair Return and Income Tax

2000			
Traditional Method			
Common Equity Ratio	53.5%	54.5%	55.5%
Equity Rate of Return	9.36%	9.25%	9.14%
Fair Return	$35.1 million	$35.0 million	$34.9 million
Income Tax*	$18.1 million	$18.2 million	$18.3 million
Fair Return & Tax*	$53.2 million	$53.2 million	$53.2 million
ATWACC Method			
$ATWACC_{BV}$ (current)	6.96%	6.96%	6.96%
$ATWACC_{BV}$ (embedded)	7.33%	7.33%	7.33%
Fair Return & Tax*	$53.2 million	$53.2 million	$53.2 million

*Book income tax only. Does not include tax adjustments.

The Board is satisfied that all of the above results fall within the range of common equity ratios and equity rates of return determined by the Board using the traditional method. The Board considers that the $ATWACC_{BV}$ model is a useful tool to ensure that the relationship between common equity ratios and equity rate of return is adjusted appropriately to arrive at the same allowed fair return and income tax components of the revenue requirement for rate-making purposes.

The Board considers it appropriate for management to retain the flexibility to determine actual capital structure within the narrow range. Accordingly, the Board considers that it is unnecessary for the Board to make a specific point determination of the common equity ratio and equity rate of return as long as the combination of the two parameters is consistent with an $ATWACC_{BV}$ (current) of 6.97% in 1999 and 6.96% in 2000.

The Board noted earlier that if it used the ATWACC method, it is extremely important for the Utilities to communicate the results of the determination of the fair return using both the traditional and ATWACC methods so that all parties clearly understand the numerical relationships between the two methods.

The Board notes that any combination of common equity ratio and equity rate of return that produces the allowed $ATWACC_{BV}$ (embedded) will produce the same fair return and income tax components of the revenue requirement. Consequently for rate-making purposes, the Board is indifferent to the combination of common equity ratio and equity rate of return. However, the Board considers that, for the purposes of the refiling and ease of communication, all schedules and tables should be prepared using the mid-point of the range determined for the traditional method (i.e. 9.25% ROE on a 54.5% common equity ratio). The Board considers that TransAlta-DISCO, in its refiling, should also demonstrate that the refiling is consistent with an allowed $ATWACC_{BV}$ (current) of 6.97% for 1999 and 6.96% for 2000 and should clearly set out the numerical relationships between the two methods similar to the format used in Appendix 2 and 3.

The Board directs TransAlta-DISCO to reflect the following in its refiling:

- A common equity ratio of 54.5% for 1999 and 2000
- An equity rate of return of 9.25%
- An $ATWACC_{BV}$ (current) of 6.97% for 1999 and 6.96% for 2000 adjusted by refiled embedded cost rates

(9) Rate Base vs. Capitalization

(A) TransAlta

The question of whether TransAlta's rate base should match capitalization on both an integrated utility and functional basis was raised by ENMAX.

Position of ENMAX

Given the evidence presented in this proceeding, ENMAX argued that TransAlta has not submitted its "real" forecast of capital structure for 1999 and 2000. TransAlta filed its original application in October 1998. In February 1999, after a round of information requests, ENMAX filed the evidence of H. W. Johnson.[467] Based on the information provided in the TransAlta

[467] Exhibit 170

Application and responses to information requests to that time, Mr. Johnson's evidence submitted that there were major problems with the TransAlta forecasts of capital structure. Mr. Johnson stated that TransAlta's forecasts of capital structure did not make sense. Specifically, there were very significant discrepancies between capitalization and rate base.

TransAlta responded to Mr. Johnson's evidence by filing rebuttal evidence,[468] claiming that Mr. Johnson's analysis was not reasonable. However, ENMAX argued that TransAlta changed the capital structure information that Mr. Johnson had relied upon. During the proceeding, TransAlta made significant changes to its forecast of capital structure,[469] correcting inconsistencies relating to errors in allocation[470] and to TransAlta's failure to resolve some financial matters prior to filing.[471] These corrections amounted to approximately two hundred million dollars for 1999, and almost a quarter of a billion dollars in 2000.[472] Even the 1998 amounts were revised by approximately $100 million.[473]

ENMAX argued that changes of this magnitude could be understandable if there had been a major change in accounting policy or procedures. However, TransAlta provided no information that would appear to indicate that was the case. Instead, ENMAX claimed that it would appear that the original filing was wrong, and TransAlta waited until just before its witnesses testified in mid-April to change the numbers.[474] ENMAX further commented that less than a month later TransAlta again revised the forecasts.[475]

ENMAX submitted that the Board should require TransAlta to obtain a special purpose audit opinion from its auditors with respect to its 1998 capitalization and refiling, as well as its pro-forma financial statements for 1999 and 2000. Without such independent verification, it is impossible for the Board, or intervenors, to obtain any comfort with respect to the forecasts provided by TransAlta unless the Board was to alter its practices to incorporate some verification or audit of the refiling.

ENMAX submitted that the capital structure and capitalization based on pro-forma financial statements are appropriate components in testing the validity of the forecasts made by TransAlta. Unless the Board goes back to the starting point each and every time it convenes a rate case, it must of necessity rely on the audited financial statements and the build-up of the assets and liabilities that are included in prior years' rate base and capitalization.

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[468] Exhibit 16
[469] Exhibit 59
[470] Tr. p.4151-4152
[471] Tr. p.4153-4154
[472] Exhibit 132
[473] Tr. p.4154-4156
[474] Exhibits 59 and 62
[475] Exhibit 134

In this context, ENMAX filed evidence by Mr. Johnson,[476] which indicated that the original filing of TransAlta appeared to be in error as to both the quantum of the capitalization versus the rate base and the allocation of the capitalization among the three functions. In addition, ENMAX argued that TransAlta's most recent filing[477] still indicated that overall (the three segments in aggregate) the capitalization exceeds the rate base plus CWIP as forecast for both 1999 and 2000. ENMAX stated that there still appears to be a problem in the functionalization of that capital amongst Generation, Transmission and Distribution.

ENMAX confirmed that for the year 1999, TransAlta functionalized approximately $13 million less capital to Generation relative to the total rate base plus CWIP[478] and about $28 million less capital to Transmission in comparison to rate base plus CWIP.[479] Conversely, the Distribution capital is greater than the rate base plus CWIP by over $73 million.

For the year 2000, the Generation capitalization is within $2 million of the rate base plus CWIP. However, the Transmission function rate base plus CWIP exceeds the functionalized capital by over $31 million.[480] As in 1999, the 2000 Distribution function capitalization exceeds the rate base plus CWIP by almost $75 million.[481] ENMAX argued that these differences indicate that there is still a problem with TransAlta's forecast capitalization and/or its functionalization of the capital and perhaps rate base as well. ENMAX stated that, as shown in Exhibit 134, page 3 of the revised response to ENMAX.TAU-52(f), the Distribution function's excess capitalization is there notwithstanding the negative short term debt (pre-funded debt), shown on line 26 of that page, of approximately $86.6 million for mid-year 1999 and $102 million for mid-year 2000. ENMAX concluded that this information indicates that there is still a problem associated with the functionalization and that there may still be a problem with the quantum of the capitalization.

Mr. Johnson indicated that non-utility assets could explain the reason for a corporate capitalization in excess of rate base plus CWIP. However, whether non-utility assets would explain the full difference of $30 million in 1999 between either the capitalization and total rate base plus CWIP and the difference of $49 million in the year 2000 is unknown since TransAlta did not consider it appropriate to provide the quantum of the non-utility assets.

ENMAX recommended that the Board should deem for each function an amount of capital required to finance rate base plus CWIP. To the extent that TransAlta has not balanced the rate base and CWIP with the capital financing it, ENMAX recommended that the capitalization should be made to be equivalent to the rate base plus CWIP, with any adjustments being made through short-term debt.

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[476] Exhibit 170
[477] Exhibit 193
[478] Exhibit 171, Table 2 Revised Line 14, Column (a) - (Column (f) + Column (h))
[479] Exhibit 171, Table 2, Line 21, Column (a) - (Column (f) + Column (h))
[480] Exhibit 171, Table 3 Revised, Line 21, Column (a) - (Column (f) + Column (h))
[481] Exhibit 171, Table 3 Revised, Line 28, Column (a) - (Column (f) + Column (h))

ENMAX stated that this adjustment should be made prior to the adjustments proposed by Drs. Waters and Winter. A further adjustment would then be required to reduce the overall common equity ratio to the 35% recommended by Drs. Waters and Winter. COCI's witnesses recommended that the excess common equity (approximately five percentage points based upon Exhibit 171 or five percentage points in 1999 and seven percentage points in 2000 based upon the TransAlta Application (section 6.1 p. 4)) should be costed as if it were preferred shares with a 5% cost.[482] ENMAX stated that the revised capital structure resulting from the above two adjustments could then be used to functionalize the capital between the three functions using the common equity ratios recommended by Drs. Waters and Winter.

Position of TransAlta

In rebuttal evidence, TransAlta responded that Mr. Johnson's evidence on behalf of ENMAX regarding the capitalization versus rate base issue was not valid. TransAlta stated that Mr. Johnson computed return based on capitalization, instead of using rate base. TransAlta further argued that Mr. Johnson ignored the fact that TransAlta calculated forecast returns based on a forecast regulated rate base financed by a recommended capital structure. Finally, TransAlta confirmed that differences between the dollar amount of total capitalization and rate base would have a relatively minor impact on the resulting return as a result of the relative weightings of no-cost capital.

TransAlta demonstrated in Schedules 1 and 2 of its rebuttal evidence, which was prepared based on revised capitalization per ENMAX.TAU-52(f), that using higher capitalization for Generation and Transmission would in fact increase returns above those filed. In contrast, there was an offsetting outcome for Distribution. TransAlta concluded that in all instances the differences represent 1% or less of the returns filed, resulting in a consolidated net understatement for the Utility.

TransAlta argued that as has been the case in previous applications, total capitalization does not exactly match rate base plus CWIP although the difference is minor. The difference between the two is primarily due to the derivation of necessary working capital for regulatory purposes in comparison to amounts based on balance sheet working capital.

TransAlta also took issue with ENMAX's view that non-utility assets could explain the reason for a corporate capitalization in excess of rate base plus CWIP. TransAlta confirmed that non-regulated assets or capitalization included in TransAlta Utilities Corporation are insignificant[483] and thus, could not materially contribute to the difference. As a result, TransAlta submitted that the evidence clearly demonstrates that the difference between capitalization and rate base for each of the test years is not caused by non-utility assets.

[482] Exhibit 162 page 65
[483] ENMAX.TAU-52(m)

3. GENCO/TRANSCO/DISCO
(i) Return

TransAlta submitted that the requested return for each of Generation, Transmission and Distribution in its Application has been determined based on forecasted rate base financed by an appropriate capital structure, including no-cost capital. Thus, ENMAX's assertion that TransAlta has materially misstated its filed returns is not valid.

TransAlta responded to ENMAX's argument that "interested parties and the Board may never know what the "real" forecast 1999 and 2000 capital structure is for TransAlta." TransAlta argued that Board approval of the ATWACC approach will make it unnecessary to determine a capital structure. Alternatively, if the Board decides to deem a capital structure, TransAlta submitted that its proposed capital structure in Exhibit 59 should be approved. If the Board deems some other capital structure, the approved capital structure would be reflected in TransAlta's refiling.

The Board previously directed TransAlta to use the actual year-end capitalization as of 31 December 1998 in its refiling. TransAlta's refiling will enable the Board and interested parties to reconcile the 1998 actual capitalization to TransAlta's 1998 Annual Report. As a result, TransAlta submitted that a special purpose audit is not required.

Board Findings

The Board considers that it is of primary importance to ensure that the rate base has been determined in a just and reasonable manner. The Board considers that it is of lesser importance that the rate base plus CWIP precisely equal the total capitalization. In this regard, the Board notes TransAlta's position that the difference is usually minor and is primarily due to the derivation of necessary working capital for regulatory purposes in comparison to amounts based on balance sheet working capital.

The Board also considers that it is of primary importance to determine the appropriate capital structure ratios and appropriate cost rates for each component of the capital structure since these are the factors that are applied to the rate base in order to arrive at the total fair return. The Board further notes that as long as the capital ratios and cost rates are determined appropriately, it is immaterial whether or not the total capital equals the rate base plus CWIP.

The Board agrees with ENMAX that the Board should deem, for each function, an amount of capital required to finance rate base plus CWIP. The Board notes ENMAX's further recommendation that to the extent that TransAlta has not balanced the rate base and CWIP with the capital that is financing it, that the capitalization should be set out to be equivalent to the rate base plus CWIP with any adjustments being made through short-term debt. The Board considers this unnecessary for the following two reasons:

- The appropriately determined capital structure will determine the appropriate amount of debt. It is not necessary to do any "balancing" to arrive at the appropriate amount of debt.

- The Board has accepted that TransAlta's cost rate for debt should include short-term debt financing as that company's financial policy leads to significant amounts of short-term debt as a permanent feature of TransAlta's capital structure.

The Board is satisfied that Exhibit 59 sufficiently reconciles mid-year investor supplied capitalization, no cost capital, customer contributions and rate base by business function.

The Board also notes that it has provided an opportunity for Intervenors to comment on the TransAlta refiling.

Notwithstanding the above, the Board directs TransAlta, in its refiling, to include a reconciliation between capitalization and rate base for the integrated utility and each of the business functions.

(B) EPGI/EPTI

The question of whether EPGI/EPTI's rate base should match capitalization was raised by Intervenors.

Position of ENMAX

With respect to EPGI and EPTI, ENMAX confirmed that both Utilities requested the use of "forecast actual" capital structures.[484] However, ENMAX argued that the term "actual" has a special meaning for EPGI and EPTI.

EPGI has requested a debt/equity ratio of 54%/46% for 1999 and 51.2%/48.8% for the year 2000.[485] ENMAX confirmed that as a result of making specific information requests with respect to financial statements and capital structure, the materials provided in the filing and the IR responses[486] did not support these ratios. ENMAX further confirmed that it discovered that the original information was not correct only after EPGI and EPTI made significant adjustments to the data during cross-examination at the hearing.

Based on the information provided during cross-examination,[487] ENMAX prepared Exhibits 31 and 32 to illustrate the "forecast" and the "applied for" (forecast actual) capital structure for EPGI. Based on the new data provided, the forecast capital structure for 1999 is a debt/equity ratio of 53.6%/46.4% while the applied-for capital structure was 54%/46%. In the year 2000, the new data provided supports a forecast capital structure of 51%/49% debt/equity, compared to the applied-for capital structure of 51.2%/48.8% indicated in the Application. ENMAX stated that while the forecast and applied-for numbers appear to be very close, it is important to bear in

[484] EPGI Application, section 3.6.2.1; EPTI Application section 3.4.2.1
[485] Volume 1, Table 12
[486] ENMAX-EPGI.22(b)
[487] (Tr. p.503, Exhibit 29, Response to Undertaking at Tr. p.507

mind that ENMAX's calculated ratios in Exhibits 31 and 32 include short-term debt in the capital structure, while the EPGI Application did not include short-term debt.

ENMAX confirmed that the situation is similar for EPTI, which requested a debt/equity ratio of 64.7%/35.3% in 1999 and 65.9%/34.1% in 2000.[488] However, based upon the information provided by EPTI with respect to the 2000 capital structure (summarized in Exhibit 33), the forecast capital structure is 70.4% debt and 29.6% equity, representing a significant disparity from what is in the Application.

ENMAX submitted that the "forecast actual" capital structures for 1999 and 2000 for EPGI should be those shown on Exhibits 31 and 32, and that the 2000 capital structure for EPTI should be that shown on Exhibit 33. ENMAX also submitted that EPTI should be directed to determine the forecast actual capital ratio for 1999 based on the revised information provided in Exhibit 37.[489]

ENMAX concluded that although EPGI and EPTI purported to request the use of "actual forecast" capital structure, neither Utility presented an actual forecast. ENMAX stated that the applied-for ratios are different from the supporting data. In addition, EPGI and EPTI are only incorporating long term debt and the shareholders' equity in their capital structure calculation. This is the case notwithstanding the inclusion of short-term debt such as bank indebtedness in their forecast balance sheets. Therefore, ENMAX argued that the Utilities are proposing neither a forecast actual capital structure nor an actual forecast capital structure.

ENMAX noted that EPGI estimated that its 1999 rate base will be $1,265.4 million, and its 2000 rate base will be $1,241.3 million.[490] However, ENMAX submitted that EPGI's 1999 capitalization is only $1,224.1 million,[491] which is $41.3 million less than the rate base. In addition, ENMAX further submitted that EPGI's capitalization for the year 2000 is only $1,197.9 million,[492] which is $43.4 million less than the requested rate base.

ENMAX argued that as a result of the discrepancy, EPGI is requesting that the Board provide it with a return based on its rated average cost of capital on $41.3 million that its investors have not supplied in 1999 and a return on $43.4 million more than its investors have supplied in 2000. According to ENMAX, the issue is whether the rate base should be deemed to be financed by capital that has not been supplied by either debt or equity investors. The corollary is that the equity investors should not obtain a return in excess of that found to be appropriate by the Board, by virtue of earning a return on capital that they have not supplied.

[488] EPTI Application, Table 4
[489] Response to Undertaking at TR 556
[490] EPGI Application, Table 7, p. 19
[491] Exhibit 31
[492] Exhibit 32

ENMAX confirmed that EPGI's balance sheets[493] indicate that the majority of the difference between rate base and capitalization is being financed by accounts payable and accrued liabilities, items which have no cost to EPGI. ENMAX argued that in a truly competitive market EPGI could not expect to charge, as a cost, its average cost of capital on capital that has not been supplied by investors in the business. As a result, ENMAX concluded that EPGI appears to be attempting to increase its costs by requesting a return on over $40 million of capital that has no cost and has not been supplied by its investors.

In response to this issue, ENMAX recommended that the Board treat these funds as zero cost capital. Alternatively, ENMAX proposed a treatment that has been employed in other jurisdictions. Specifically, the Board could allow a return on the capital that was not supplied by investors ($41 to $43 million), but establish a rate for this capital that is no higher than the cost of short-term debt, i.e. 4% to 5%.

In reply argument, ENMAX noted that, contrary to EPGI's argument that no intervenor took issue with the forecast actual capital structure, ENMAX had specifically taken issue with the amounts forecast for EPGI and EPTI. ENMAX confirmed that it would not object to the use of forecast actual capital structures in the case of EPGI and EPTI provided that the capital structure includes all of the capital deemed to be financing the rate base, CWIP and other assets of the companies and provided that capitalization equals or exceeds the rate base, CWIP and other assets. ENMAX argued that all capital should include short-term debt in the capital structure, since short-term debt is used to finance a portion of rate base and CWIP.

Position of the FIRM Customers

The FIRM Customers supported ENMAX's recommendation that the portion of the EPGI's rate base that is greater than capitalization be should be treated either as no-cost capital or be assigned a short-term debt rate. The FIRM Customers were specifically concerned that EPGI is financing a portion of its rate base using no-cost capital such as accounts payable and other accrued liabilities.

Position of EPGI and EPTI

ENMAX stated that EPGI's capital structure has not been reliably forecast for reasons arising out of the cross-examination of Mr. Vaasjo. However, EPGI stated that Mr. Vaasjo described three key differences between the 1 January 1999 actual balance sheet and the forecast balance sheet set out in the Application, summarized as follows:

- In the forecast, the investment in the dragline has been improperly assumed to be part of property, plant and equipment. In fact, that specific investment has been written off.
- EPGI's auditors have not permitted the recording of allocated EPCOR corporate assets on the EPGI balance sheet even though those assets are properly part of the EPGI rate base. The forecast for regulatory purposes includes the allocated EPCOR corporate assets.

[493] Exhibit 30

- The actual equity component of the EPGI's capitalization was established at a somewhat higher level than forecast.

EPGI submitted that the Board should accept its forecast capital structure. If not, the Board should make an upward adjustment to the applied-for common equity ratio to reflect the actual dollars of common equity committed as of January 1999.

EPGI disagreed with ENMAX's argument that rate base is not equivalent to capitalization. In particular, EPGI was critical of the assertion that its investors are improperly receiving a return on dollars they have not invested and the suggestion that the difference between rate base and capitalization should be considered as either no-cost capital or short-term debt. EPGI argued that ENMAX's argument should be rejected for three reasons:

- The ENMAX proposal is inconsistent with the long-established practice of considering that the capital structure ratios are the notional means by which the rate base assets are financed. Rate base and capitalization will never precisely equal each other.
- ENMAX's proposal is self-serving since it does not make the contrary proposal in respect of EPTI, a company whose capitalization exceeds its rate base.
- ENMAX's claimed difference between rate base and capitalization can been completely reconciled.

EPGI argued that there are errors in Exhibits 31 and 32. They were based on the legal balance sheets of EPGI in 1999 and 2000. These balance sheets do not include the corporate assets of EPCOR allocated to EPGI. The value of these specific assets is approximately $19-20 million. EPGI confirmed that the net debt balance (i.e., gross debt net of the amounts in the sinking funds) was higher for regulatory purposes than the net debt balance on the legal financial statements. Also, another reason for the difference was that the cumulative amount of sinking fund earnings excluded for regulatory purposes was $70-80 million. Finally, the working capital showing on the balance sheet represented a year-end snapshot, which is significantly different from regulatory necessary working capital or the average working capital required. For example, over the last three years there has been an average swing of $50 million in EPGI's short-term debt within each year, demonstrating the average swing in working capital.

EPGI submitted that the allocated assets, sinking fund earnings and working capital differences substantially account for the differences between rate base plus decommissioning reserve and capitalization. As a result, the $41-43 million difference between rate base and capitalization has been reconciled. Consequently, EPGI concluded that the Board should reject ENMAX's recommendation that the $41-43 million should be treated as no-cost capital.

Board Findings

The Board considers that it is of primary importance to ensure that the rate base has been determined in a just and reasonable manner. The Board considers that it is of lesser importance that the rate base plus CWIP precisely equal the total capitalization. In this regard, the Board

notes EPGI's position that the allocated assets, sinking fund earnings and working capital differences substantially account for the differences between rate base plus CWIP plus decommissioning reserve and capitalization.

The Board also considers that it is of primary importance to determine appropriate capital structure ratios and appropriate cost rates for each component of the capital structure since these are the factors that are applied to the rate base in order to arrive at the total fair return. The Board further notes that as long as the capital ratios and cost rates are determined appropriately, it is immaterial whether or not the total capital equals the rate base plus CWIP.

The Board is not persuaded by the arguments of ENMAX and the FIRM Customers that the Board should deem the difference between capitalization and rate base as no-cost capital. The Board considers this unnecessary for the following two reasons:

- It would not be fair or reasonable to deem that the assets allocated from EPCOR and differences between regulatory and balance sheet working capital are financed by no-cost capital or short-term debt. These allocated assets and working capital differences account for a large portion of the difference between EPGI's capitalization and rate base.
- The Board has accepted that EPGI/EPTI's argument that its cost rate for debt should not include short-term debt financing as the financial policy of EPGI/EPTI's management is to not incur significant amounts of short-term debt on a long-term basis.

The Board is satisfied that EPGI has adequately explained the reasons for the difference between its rate base and capitalization. At the same time, the Board notes that no explanation was given for the difference between EPTI's rate base and its capitalization.

The Board also notes that it has provided an opportunity for Intervenors to comment on the EPGI/EPTI refilings.

Notwithstanding the above, the Board directs EPGI and EPTI, in their refilings, to include a reconciliation between capitalization and rate base.

(j) Aboriginal Issues

Position of the First Nations

The First Nations noted that activities taking place on Federal Indian Reservations that earn money involving Status Indians are not subject to income tax. The First Nations therefore submitted that, if income tax is being paid to the federal government as a result of monies earned on federal Indian lands, the revenue should not attract income tax. The First Nations stated that this should be a flow through issue as far as utilities are concerned. However the utilities would have to identify that portion of the rate that is charged to First Nations that is related to income tax. The First Nations requested that such a direction be made to the Utilities. In an attempt to determine who the aboriginal customers are, the First Nations proposed that Aboriginal

customers be allowed to come forward and identify themselves. The First Nations proposed that the income tax component of the rate for Aboriginal customers that identified themselves as such could go into a fund. The fund could be accumulated and ear marked for some Utility sponsored or band sponsored projects to increase consultation between the bands and the Utilities.

With respect to property taxes paid on Aboriginal land, the First Nations submitted that there should be an equitable treatment between property taxes paid on Aboriginal land to that paid on other land. The First Nations also suggested that there should be help provided to bands to clarify the costs associated with new service extensions and how the delineation between rural (farm) and urban (residential) service is made.

The First Nations questioned whether all of the assets used to service a band could be distinguished from other assets. The First Nations suggested that this would facilitate the First Nations being able to evaluate their options with respect to purchasing lines on their land.

With respect to Sustainable Development projects forecast by TransAlta, the First Nations suggested that TransAlta could consult with the Peigan First Nation to determine whether their wind generation project meets the criteria called for in the Kyoto Protocol.

The First Nations noted that First Nations could own transmission facilities that traverse their land. The First Nations requested that the Utilities be directed to be open to this possibility.

The First Nations stated that there should be some recognition that much of the administrative load required in providing services to bands is provided by the bands themselves. The First Nations noted that utilities set up offices in towns off reserve that in some situations primarily deal with service issues for a particular First Nation. The First Nations suggested that if band administration offices were given agency status they could serve both the band and the Utility. The First Nations argued that such an arrangement could provide band members a greater part in managing their own affairs, save money and presumably reduce the rates they are required to pay for their service. The First Nations noted with appreciation that, as a result of the hearing process, the Utilities have expressed a willingness to meet with the First Nations and address aboriginal issues.

The First Nations suggested that it would be helpful if the Utilities were directed to consider ways and means by which customer contact with Aboriginal communities could be enhanced and improved. The First Nations stated that it might be necessary to consider several different approaches in order to have effective instruments in place to achieve consultation with Aboriginal constituents at the customer level.

The First Nations submitted that the area of deposits on new accounts is one where policies applied to other customers create difficulty with respect to First Nations customers. One of the characteristics of portions of the First Nations constituency is that it is highly transitory. For example, a particular house may change hands five or six times in a four or five month period

and each time a deposit is required. The rate at which deposits find their way back to the bands is slow. The First Nations suggested that some alternative arrangements backstopped by the band might facilitate this situation. This could be negotiated between the utility and the bands and be appended to the Terms and Conditions of Service.

Position of TransAlta

TransAlta recognized that its relationship with aboriginal communities is very important, and as a result, has made a conscious and deliberate effort to improve relationships with aboriginal communities and strives to create relationships that are mutually beneficial. For example, the Generation business unit made the commitment to have all employees attend Aboriginal Awareness Workshops in 1998. TransAlta noted details of employment opportunities for members of aboriginal communities within TransAlta, including the creation of an apprenticeship program in the area of mechanical maintenance and ongoing contractual relations with, for example, members of the Paul Band. In addition, TransAlta supported the creation of an Aboriginal Council for employees within the power stations and TransAlta meets with the Paul Band Liaison Committee on a quarterly basis in order to address issues arising from the ongoing relationship between TransAlta and the aboriginal communities.

TransAlta stated that similar initiatives were undertaken in the Transmission and Distribution business units. TransAlta employs some linemen from aboriginal communities and actively recruits aboriginal students from universities across the country for employment. TransAlta identified specific employees as being responsible for maintaining and building relationships with Indian Bands and Reserves. During the time that the Call Centre was being constructed, a conscious effort was made to have aboriginal representation included amongst the employees at the Call Centre.

In response to the argument of the First Nations, TransAlta submitted that several matters raised, such as issues relating to income tax and customer deposits, are rate issues which are more appropriately addressed in the context of a Phase II proceeding.

TransAlta submitted that the steps it has taken demonstrates that TransAlta has already made considerable efforts to consult with the Aboriginal community regarding a number of issues and continues to proactively cooperate with First Nations groups. Accordingly, TransAlta submitted that there is no need for the various directions sought by the First Nations.

Board Findings

The Board notes with approval that the Utilities indicated willingness to meet with representatives of the First Nations to discuss some of the issues that were raised during the hearing. The Board considers that this is likely the most appropriate and effective manner of dealing with many of the issues raised by the First Nations such as employment opportunities, use of Band offices as agents and sustainable development projects on First Nation lands. The Board also notes that the Utilities' Terms and Conditions of Service set standards that must be met by the Utilities. The Utilities have the ability to apply these rules more liberally and often do

provided there is no detrimental effect on other customers. It is not the purpose of the Terms and Conditions of Service to cover all possibilities and eventualities, as this is not practicable.

The Board also notes that Utilities do not maintain their asset accounts to facilitate the potential purchase of utility property. The Board considers that it would be a costly process to alter the Utility asset system of accounts so that all property on First Nations land could be separated from other assets. Accordingly, the Board does not accept this proposal of the First Nations.

The Board notes that income tax is a cost incurred by Utilities to provide utility service to their customers. Therefore it is appropriate that income tax is allowed to be recovered through customer rates. To the extent that a utility is not exempt from paying income tax to serve Aboriginal customers, it is reasonable that the utility be allowed to collect income tax through its rates from those customers.

4. SUMMARY OF BOARD DIRECTIONS

This section is a summary[494] of Board directions to AE, EPGI/EPTI and TransAlta in Part 1–General. The Directions in *italics* are to be complied with in the 1999 refilings. The remaining directions are to be complied with in the future or at the time of the next GTA.

1. *The Board has found it necessary to direct the Utilities to refile their Applications to reflect the findings of the Board in this Decision. The Board directs:*

    - *EPGI, EPTI and TransAlta to refile their Applications using 1 January 1999 actual plant balances, accumulated depreciation and capitalization.*
    - *EPGI and EPTI to incorporate all corrections and adjustments listed in Exhibit 8 in their refiling.*
    - *TransAlta to incorporate all corrections and adjustments listed in Exhibits 59, 75 and 169 in their refiling and the correction noted in TransAlta's letter to the Board dated 29 October 1999.*
    - *AE, EPGI, EPTI and TransAlta to refile their Applications to comply with the findings of the Board in this Decision.* [Section 1(b)]

2. *The Board directs that the refilings be in sufficient detail to clearly demonstrate compliance with the Board's findings. The refiling should capture all of the intricate interrelationships among the generation forecast, the Utilities' revenue requirements and prices and tariffs.* [Section 1(b)]

3. *The Board directs the Utilities to circulate the refilings to all registered parties in this proceeding for the sole purpose of ensuring that the refilings conform to the findings of the Board. The Board will provide Intervenors with an opportunity to comment on the refilings. In the event that the refiling is not in sufficient detail to clearly demonstrate compliance with the Board's findings, the Board may allow an Information Request and Response process.* [Section 1(b)]

4. *The Board directs AE, EPGI, EPTI and TransAlta, in their refilings, to clearly state that their prices and tariffs are in effect on a final basis only until 31 December 2000.* [Section 1(c)]

5. The Board directs AE, EPGI, EPTI and TransAlta to file an application for rates effective 1 January 2001 if such new rates require Board approval. [Section 1(c)]

6. *To assist in this regard, the Board directs the Utilities to include in their refiling a reconciliation schedule, which clearly sets out the differences between the refiling for*

[494] This summary has been prepared for the convenience of all parties. The directions in the main body of the Decision shall prevail over this summary if there are any differences.

1999 and 2000 and what was provided to the IAT for inclusion in the PPA process. [Section 2(b)]

7. Therefore, the Board directs EPGI, if a future GTA is required, and EPTI, at the next GTA, to provide valuations of assets and properties that have been transferred between entities and agreements that support such transfers. [Section 2(c)(2)]

8. In order to ensure that these transactions are following fair market prices, the Board directs EPTI to keep track of and report on, in future GTAs, the amount of manpower used by non-regulated entities from EPTI. [Section 2(c)(2)]

9. Accordingly, in future GTAs, the Board directs EPTI to provide the following information on contracts or services that result in amounts being charged to the regulated utility by unregulated affiliates or that the regulated utility charges to unregulated affiliates:

   - A list of services provided or received.
   - The annual amount associated with those services.
   - The contract or service agreement supporting those charges.
   - How the rate or charge was determined and how does it relate to a market assessment of the reasonability of those charges. [Section 2(c)(2)]

10. In order to ensure that these transactions are following fair market prices, the Board directs TransAlta to keep track of and report on, in future GTAs, the amount of manpower used by non-regulated entities from the regulated TransAlta affiliates. [Section 2(c)(3)]

11. Accordingly, in future GTAs, the Board directs TransAlta to provide the following information on contracts or services that result in amounts being charged to the regulated utility by unregulated affiliates or that the regulated utility charges to unregulated affiliates:

   - A list of services provided or received.
   - The annual amount associated with those services.
   - The contract or service agreement supporting those charges.
   - How the rate or charge was determined and how does it relate to a market assessment of the reasonability of those charges. [Section 2(c)(3)]

12. However, if the need arises, the Board directs the Utilities to perform the above noted calibration either individually or as a joint effort at the time of the next GENCO GTA. [Section 3(a)(1)(B)]

13. The Board also directs the Utilities to prepare a distribution of the pool price forecast and confidence intervals of such a forecast as a means of calibrating to the actuals. [Section 3(a)(1)(B)]

14. *Accordingly, the Board directs TransAlta, in its refiling, to use 14 iterations of the ENPRO model to mitigate the non-convergent infirmity of the ENPRO model.* [Section 3(a)(1)(C)]

15. However, the Board notes that if a future GENCO GTA is required, the Utilities should exclude outages for which relief was granted under a TSR Application when calculating FMORs and ACFs. [Section 3(a)(1)(D)(i)]

16. *Therefore, the Board directs the Utilities to recalculate FMORs and ACF using 1996, 1997 and 1998 data and to use these recalculated parameters in their refiling.* [Section 3(a)(1)(D)(i)]

17. *Nevertheless, the Board directs the Utilities, in their refilings, to avoid double counting forced outages and planned outages in their forecasts.* [Section 3(a)(1)(D)(i)]

18. *For the purposes of the refiling, the Board directs the Utilities to use an increment for economic generation above MCR of +0.4 for all units.* [Section 3(a)(1)(D)(ii)]

19. *Accordingly, the Board directs EPGI, in its refiling, to submit the results of the re-runs of PROSYM incorporating all of the Board's findings in this Decision respecting modeling.* [Section 3(a)(1)(E)(ii)]

20. *TransAlta is directed, in its refiling, to use the EPGI re-runs in TransAlta's refiling of forecast hydro surplus/shortfall.* [Section 3(a)(1)(E)(ii)]

21. *TransAlta is also directed, in its refiling, to submit the results of the re-runs of ENPRO incorporating all of the Board's findings in this Decision respecting modeling.* [Section 3(a)(1)(E)(ii)]

22. *The Board considers that the Utilities should use a common maintenance schedule and therefore, directs EPGI to re-file its forecast with the planned turnarounds for Wabamun as submitted by TransAlta.* [Section 3(a)(1)(E)(iii)]

23. *The Board, therefore, directs EPGI, in its refiling, to re-run PROSYM using all the parameters and techniques prescribed in this Decision and the following directions to obtain an appropriate ancillary service baseline forecast:*
    - *EPGI should run PROSYM to forecast ancillary service revenue, i.e., variable payments for constrained on generation for transmission system support (or out of merit), variable payments for spinning reserve and variable payments for AGC.*

- *EPGI should maintain its assumption respecting the amount of spinning reserve available from hydro units, as EAL did not substantiate its submission that there is less spinning reserve available from hydro.*
- *EPGI should run PROSYM seven times when forecasting ancillary service revenues. Each run should consist of two cases, one with and one without unit constraints for ancillary services, but the same pattern of outages should be maintained. The difference between these two cases yields the ancillary service revenue for one run. This process shall be repeated seven times and the results averaged. EPGI should use the ACFs that include operation on AGC in the case with units constrained for ancillary services. However, the ACFs should not include operation on AGC in the case without unit constraints for ancillary services. EPGI should conduct separate simulations for the years 1999 and 2000.* [Section 3(a)(1)(E)(iv)]

24. *The Board directs TransAlta to incorporate the results for ancillary services from EPGI's PROSYM runs in its refiling.* [Section 3(a)(1)(E)(iv)]

25. *Accordingly, the Board directs TransAlta, in its refiling, to use a forecast of $5.5 million for 1999 and $5.3 million for 2000 for hydro ancillary services.* [Section 3(a)(1)(E)(iv)]

26. *Accordingly, the Board directs EPGI and TransAlta, in their refilings, to include the following new generating units in their 1999 and 2000 forecasts:*

Power Plant Name (Location) Company Name per EUB Approval	In-Service Date	1998 Output (MW)	1999 Output (MW)	2000 Output (MW)
Drayton Valley Power (Dapp Area) DVP Purchase Corp., Westlock Power	1-Sep-98	17		
Grande Prairie Plant (Poplar Hill) CU Power Canada Limited	1-Nov-98	40		
Primrose Plant CU Power Canada Limited and Amoco Canada Resources Ltd.	1-Nov-98	84		
Rainbow Lake Plant CU Power Canada Limited	1-Jan-99		40	
Fort Nelson Plant (British Columbia) No EUB Approval	1-Jan-99		40	
Dow Fort Saskatchewan Plant TransAlta Energy Corporation and Air Liquide Canada Inc.	1-Dec-99		40	
Taylor Chute Plant (Magrath Area) Canadian Hydro Developers Inc.	1-Jun-00			12.5
Scotford Plant (Fort Saskatchewan) Air Liquide Canada Inc.	1-Jul-00			49
Joffre Plant NOVA Chemicals Limited	1-Apr 00			461
Suncor Plant Unit 1 (Fort McMurray) TransAlta Energy Inc.	1-Dec-99		115	
Suncor Plant Unit 2 (Fort McMurray) TransAlta Energy Inc.	1-Jan-00			115
Suncor Plant Unit 3 (Fort McMurray) TransAlta Energy Inc.	1-Feb-00			60
Suncor Plant Unit 4 (Fort McMurray) TransAlta Energy Inc.	1-Oct-00			70
Plant in M.D. of Pincher Creek Canadian Gas and Electric Ltd.	1-Oct-99		6	
Gold Creek Plant (Grande Prairie) NOVA Pipelines Venture	1-Jun-99		6.5	
Plant on East Bank of Castle River Vision Quest Windelectric Inc.	1-Dec-00			6.6
Flare/Solution Gas Units Renaissance Energy Ltd.	1-Oct-99		2	
TOTAL		141	249.5	774.1

[Section 3(a)(1)(F)(i)]

27. *The Board directs EPGI and TransAlta, in their refilings, to either include in their load forecast the full load of these industrial complexes or to decrease the outputs of the units such that only the net energy supplied to the pool is included in the modeling.* [Section 3(a)(1)(F)(i)]

28. *Therefore, the Board directs EPGI and TransAlta, in their refilings, to use the following monthly MW output for the Taylor Chute plant to account for water availability:*

Month	Output (MW)
January	0
February	0
March	0
April	2.2
May	9
June	12
July	12.5
August	11.2
September	7.1
October	3
November	0
December	0

[Section 3(a)(1)(F)(i)]

29. *Therefore, the Board directs EPGI and TransAlta, in their refilings, to use a FMOR of 50% to account for wind availability.* [Section 3(a)(1)(F)(i)]

30. *Therefore, the Board directs EPGI and TransAlta, in their refiling of modeling re-runs, to change the assumptions respecting the way the SaskPower Tie was modeled such that the forecast of imports from SaskPower will exceed 200 GWh in 1999. The revised 1999 assumptions should also be used for the year 2000.* [Section 3(a)(1)(H)]

31. *Therefore, the Board directs TransAlta and EPGI, in their refilings, to include a third 200-MW block of capacity, for a total of 765 MW, available for B.C. Hydro imports to be offered at $250 per MWh.* [Section 3(a)(1)(H)]

32. *Accordingly, the Board directs EPGI and TransAlta, in their refilings, to calculate revised generator excitation costs applicable for each of the test years 1999 and 2000 as follows:*
    - *Net plant (i.e. rate base) to be reduced to account for accumulated depreciation for the period 1996-2000.*
    - *Composite rate of return to correspond with the Board's findings in this Decision respecting fair return.*
    - *Income tax, in the case of TransAlta, to correspond with the Board's findings in this Decision respecting Income Tax.*
    - *Maintenance and overhead costs to correspond with the Board's findings in this Decision.* [Section 3(a)(3)(A)]

33. The Board directs that AE's generator excitation costs should be reduced by the percentage reduction (i.e., 7% for 1999 and 8% for 2000) to the requested GENCO reservation price agreed to in the AE negotiated settlement. [Section 3(a)(3)(A)]

34. *The Board directs EPGI and TransAlta, in their refilings, to reflect the above recalculated Dynamic Voltage Support costs. The Board notes that the change to the AE costs will be dealt with pursuant to the terms of the AE negotiated settlement.* [Section 3(a)(3)(A)]

35. The Board directs EPGI and TransAlta to calculate revised fixed payments for all remaining items other than "Hydro Motoring" applicable for each of the test years 1999 and 2000 as follows:
    - Net plant (i.e. rate base) to be reduced to account for accumulated depreciation for the period 1996-2000.
    - Composite rate of return to correspond with the Board's findings in this Decision respecting fair return.
    - Income tax, in the case of TransAlta, to correspond with the Board's findings in this Decision respecting Income Tax.
    - Maintenance and overhead costs to correspond with the Board's findings in this Decision. [Section 3(a)(3)(A)]

36. *For Hydro Motoring energy and capacity costs, the Board directs TransAlta, in its refiling, to use the Rate 790 rate in effect in October 1998 at 50% load forecast and 13.8 MW of Demand consistent with the methodology used in Decision U97065.* [Section 3(a)(3)(A)]

37. The Board directs that AE's remaining voltage control and system security costs should be reduced by the percentage reduction (i.e. 7% for 1999 and 8% for 2000) to the requested GENCO reservation price agreed to in the AE negotiated settlement. [Section 3(a)(3)(A)]

38. Therefore, the Board directs that these provisions also be incorporated into the AE and EPGI System Support Service Agreements as they have been approved for the Transmission Terms and Conditions. [Section 3(a)(3)(A)]

39. Therefore the Board directs that within 30 days following the issuance of this Decision, AE and EPGI are to report on their progress towards reaching agreements on system support services. [Section 3(a)(3)(A)]

40. The Board directs that a pool price deferral account be established by EPGI and TransAlta with the amount to be deferred in respect of each hour to be calculated as follows:

    Pool price deferral = (Actual pool price-Forecast pool price) x (Forecast generation by unit) + (Forecast unit obligation value – Actual unit obligation value)
    [Section 3(a)(4)(A)]

41. The Board directs that the above deferral account formula should use a forecast hourly pool price, forecast hourly generation by unit and forecast hourly UOV developed for EPGI's and TransAlta's thermal generating units as follows:

- Develop an average hourly pool price, average hourly generation and average hourly UOV by thermal unit by averaging EPGI's PROSYM modeling iterations.
- Develop an average hourly pool price, average hourly generation and average hourly UOV by thermal unit by averaging TransAlta's ENPRO modeling iterations.
- Develop the forecast average hourly pool price, forecast average hourly generation and average hourly UOV for EPGI's and TransAlta's thermal units by averaging the above EPGI and TransAlta averages. [Section 3(a)(4)(A)]

42. Further, the Board directs that the above deferral account formula should use a forecast hourly pool price, forecast hourly generation by unit and forecast hourly UOV developed for TransAlta's hydro generating units as follows:

- Develop the forecast average hourly pool price, forecast average hourly generation and average hourly UOV for TransAlta's hydro units by averaging EPGI's PROSYM modeling iterations. [Section 3(a)(4)(A)]

43. *Accordingly, the Board directs, for the purposes of the refiling, that all forecast modeling parameters be determined using actual performance data over the three-year period 1996-1998.* [Section 3(a)(4)(A)]

44. Accordingly, on balance the Board directs EPGI and TransAlta to establish a deferral account for ancillary service revenue in which the revenue variance is shared 90% to customers and 10% to the Utilities. [Section 3(a)(4)(B)]

45. The Board directs that, in the post 1999/2000 timeframe, the TFOs should be consistent in what they include in planning costs. [Section 3(b)(2)]

46. Also the Board directs that the TA and the TFOs address, in the next GTA, the staff planning requirements in order to minimize any duplication of service and costs. [Section 3(b)(2)]

47. At the next GTA, the Board directs the TFOs to bring forward their recommended guidelines, after consultation with the TA, for resolving any perceived or unfair advantages that regulated TFOs might have in bidding on unregulated projects. [Section 3(b)(2)]

48. *Accordingly the Board directs TransAlta, in its refiling, to increase its forecast of 1999 customer contributions by $10 million.* [Section 3(b)(3)]

49. *Accordingly, the Board directs TransAlta, in its refiling, to remove the capital additions associated with the Cheviot project from the rate base for the test years.* [Section 3(b)(3)]

50. The Board considers that the relatively high percentage of unassigned expenditures, together with the previously mentioned forecasting difficulties, have combined to create a high degree of uncertainty with respect to transmission capital addition forecasting and therefore:
    - In order to insure that any under or over forecasting of capital addition expenditures is captured, the Board directs the TFOs to establish a deferral account commencing in the 1999-2000 period.
    - At the time of the next GTA, the Board will deal with any variance arising in 1999-2000 to the capital addition forecast, including additional projects and actual costs that were assigned to the TFO. [Section 3(b)(3)]

51. Similarly, in the post 1999/2000 timeframe, the Board directs that the TFOs only include capital maintenance and directly assigned projects in their respective capital addition budgets. As well, the budget for remaining system additions, including customer requests that a project be sent out for RFP, should be included in the TA budget. [Section 3(b)(3)]

52. *Further, the Board directs AE, EPGI and TransAlta, in their refilings, to clearly identify the amount of capital maintenance included in the refiled capital budget.* [Section 3(b)(3)]

53. *Further, the Board directs AE, EPGI and TransAlta, in their refilings, to include a definition of capital maintenance projects and to separately identify any major projects so that the Board and interested parties can understand what has been put into this category.* [Section 3(b)(3)]

54. *The Board directs AE, EPTI and TransAlta, in their refilings, to delete Sections 7.1(c) to (g) and Section 7.1(h) from their T&C. The Board directs EPTI, in its refiling, to replace Sections 7.1(c) to (g) with the agreed upon Sections 7.1(c) to (d).* [Section 3(b)(4)(B)]

55. Accordingly, the Board approves the Section 9 arbitration provision of the T&Cs and the Board directs the inclusion of the following provisions:

    - The TFO is required to advise the Board of any matter going to arbitration within 30 days of the matter being referred to arbitration. In addition, the TFO shall advise the Board of the results of arbitration within 30 days of the Arbitrator's decision.
    - At the same time, the TFO shall provide the Board with a list of potentially affected parties.
    - Any interested party adversely and unduly affected by the interpretation or application of the T&Cs, whether from a negotiation, compromise or arbitration, is entitled to make an application to the Board requesting a clarification or change to the T&Cs in the first instance. [Section 3(b)(4)(D)]

56. The Board considers, however, the following direction from Decision U97065 to still be appropriate after parties have successfully completed negotiations and are seeking the Board's approval of a negotiated settlement:

When applications for approval are filed, the Board would find the following information useful:

- a fully-supported base-year forecast;
- a description of the performance targets that will be used and the means by which performance will be measured;
- a description of the method of identifying cost savings or other benefits;
- a description of the manner in which cost savings or other benefits will be shared between the utility and customers;
- a discussion of how the tariff may change over the period in which it is intended to have effect; and
- a discussion of the content of periodic reports to be filed with the Board and interested parties for the purpose of monitoring results under the form of Incentive Regulation being proposed. [Section 3(b)(5)]

57. The Board directs that interested parties advise the Board of the status of Incentive Regulation negotiations by the next GTA. [Section 3(b)(5)]

58. Accordingly, the Board directs that a pool price deferral account be established by TransAlta DISCO for the 1999-2000 period with the amount to be deferred in respect of each hour to be calculated as follows:

Pool price deferral = (Actual pool price-Forecast pool price) x (Forecast energy purchases) + (Actual DISCO entitlement – Forecast DISCO entitlement)

[Section 3(c)]

59. The Board directs that the above deferral account formula should use a forecast hourly pool price, forecast hourly energy purchase and forecast hourly DISCO entitlement developed as follows:

- Develop an average hourly pool price, average hourly energy purchase and average hourly DISCO entitlement by DISCO by averaging EPGI's PROSYM modeling iterations.
- Develop an average hourly pool price, average hourly energy purchase and average hourly DISCO entitlement by DISCO by averaging TransAlta's ENPRO modeling iterations.
- Develop the forecast average hourly pool price, forecast average hourly energy purchase and average hourly DISCO entitlement by averaging the above EPGI and TransAlta averages. [Section 3(c)]

4. SUMMARY OF BOARD DIRECTIONS

60. Accordingly, the Board directs TransAlta to establish a further DISCO deferral account as described above. [Section 3(c)]

61. Therefore the Board directs both TransAlta and EPGI to apply to the Board for approval to collect or refund the balance in their deferral accounts (e.g., GENCO accounts for EPGI and GENCO and DISCO accounts for TransAlta) by 1 April 2000 for disposition of the balances at year-end 1999 and by 1 April 2001 for disposition of the balances at year-end 2000. [Section 3(d)]

62. Accordingly, the Board directs AE, EPGI, EPTI and TransAlta to follow and make available the equivalent audit processes and provisions to accounts and balances being handled by the Balancing Pool as described in this section on the audit of Deferral Accounts. The Board directs that the same provisions for paying for the audit process will apply as described in this section. [Section 3(d)]

63. The Board directs TransAlta and EPGI to include the following in their application:

- Provide an accounting of the final balances in their applicable deferral accounts and a proposal to deal with their disposition to all parties to the 1999/2000 proceeding.
- Allow any party/parties to the 1999/2000 proceeding audit rights (using an auditor acceptable to the Utility and the party/parties) in respect to compliance with the specific terms of each deferral account, providing the party/parties agree to fund the audit and provide the Utility with a copy of the audit report prepared by the person(s) performing the audit.
- Provide all reasonable cooperation necessary for the effective and efficient completion of any audit. [Section 3(d)]

64. Further, the Board directs that the parties apply to the Board, upon completion of the audit, for a determination of how the costs of the audit should be split amongst the parties. The Board will determine who should pay the cost of the audit. The Board considers that the costs may be:

- Shared among the Utility, its customers and the party requesting the audit in the normal course of events, Alternatively, the costs could be recovered from the savings identified in the audit..
- Borne by the Utility if, for example, the error arose from a lack of attention to the Board's directions, or.
- Borne solely by the party requesting the audit if, for example, if the Board were to determine that the audit was vexatious or frivolous. [Section 3(d)]

65. Accordingly, the Board directs EPGI and TransAlta to establish a deferral account for the year 2000 for GENCO taxes other than income only if assessment rules are changed and are applicable to the 2000 tax year. [Section 3(e)]

4. SUMMARY OF BOARD DIRECTIONS

66. The Board directs EPGI and TransAlta to apply to the Board for approval of the disposition of any positive or negative balances in the deferral account. [Section 3(e)]

67. With respect to interest on any outstanding balance in any account to be handled through Balancing Pool as of 31 December 2000, the Board directs that its normal Guideline on interest will apply [Section 3(g)]

68. *Therefore, the Board directs TransAlta to refile its embedded cost of debt for 1999 and 2000 incorporating the mid-year forecast amount of customer deposits.* [Section 3(i)(1)]

69. *The Board directs TransAlta to incorporate a dividend rate of 5.25% for its proposed preferred share issue in its refiling of revenue requirement.* [Section 3(i)(2)]

70. *Accordingly, the Board directs TransAlta, in its refiling, to reflect the following in its integrated utility refiling:*

- *An integrated common equity ratio of 41%*
- *An equity rate of return of 9.25%*
- *An ATWACC$_{BV}$ (current) of 6.18% for 1999 and 6.17% for 2000 adjusted per refiled embedded cost rates*
- *Ensure that the refiled fair return and income tax for the integrated utility reconciles with the sum of the refiled fair return and income tax of the business functions. The integrated common equity ratio may be adjusted slightly, if necessary, to achieve this reconciliation.* [Section 3(i)(5)]

71. *The Board directs TransAlta-GENCO to reflect the following in its refiling:*

- *A common equity ratio of 40%*
- *An equity rate of return of 9.25%*
- *An ATWACC$_{BV}$ (current) of 6.12% for 1999 and 6.11% for 2000 adjusted for refiled embedded cost rates* [Section 3(i)(6)(A)]

72. *The Board directs EPGI to reflect the following in its refiling:*

- *A common equity ratio of 44%*
- *An equity rate of return of 9.25%*
- *An ATWACC$_{BV}$ (current) of 7.41% for 1999 and 7.41% for 2000 adjusted per refiled embedded cost rates* [Section 3(i)(6)(B)]

4. SUMMARY OF BOARD DIRECTIONS

73. *The Board directs TransAlta-TRANSCO to reflect the following in its refiling:*

- *A common equity ratio of 35%*
- *An equity rate of return of 9.25%*
- *An $ATWACC_{BV}$ (current) of 5.83% for 1999 and 5.82% for 2000 adjusted per refiled embedded cost rates* [Section 3(i)(7)(A)]

74. *The Board directs EPTI to reflect the following in its refiling:*

- *A common equity ratio of 35%*
- *An equity rate of return of 9.25%*
- *An $ATWACC_{BV}$ (current) of 7.11% in 1999 and 2000 adjusted for refiled embedded cost rates* [Section 3(i)(7)(B)]

75. *The Board directs TransAlta-DISCO to reflect the following in its refiling:*

- *A common equity ratio of 54.5% for 1999 and 2000*
- *An equity rate of return of 9.25%*
- *An $ATWACC_{BV}$ (current) of 6.97% for 1999 and 6.96% for 2000 adjusted by refiled embedded cost rates* [Section 3(i)(8)]

76. *Notwithstanding the above, the Board directs TransAlta, in its refiling, to include a reconciliation between capitalization and rate base for the integrated utility and each of the business functions.* [Section 3(i)(9)(A)]

77. *Notwithstanding the above, the Board directs EPGI and EPTI, in their refilings, to include a reconciliation between capitalization and rate base.* [Section 3(i)(9)(B)]